A $4 Billion Bailout in the Buckeye State: FirstEnergy's Plan Will Cost Customers for Years to Come

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Executive Summary

FirstEnergy is pushing for utility regulators in Ohio to allow it to pass long-term costs and risks of three aging coal-fired plants and one aging nuclear plant onto captive customers of the utilities.

The company's campaign for a ratepayer bailout of these plants—the coal-fired W.H. Sammis plant, the nuclear Davis-Besse plant and FirstEnergy's share of the coal-fired Clifty Creek and Kyger Creek plants—marks a reversal from a time in which FirstEnergy was able to make money on them. Today, the plants are unprofitable, and are likely to remain so for years to come.

FirstEnergy executives recognize this reality, which is why their proposal aims to transfer costs and risks to customers. The arrangement FirstEnergy seeks would essentially turn ratepayers into de facto merchant generators vulnerable to the same difficult economic trends and market conditions that have plagued other merchant power generators in recent years.

What makes these coal-power plants so costly and risky, and the reasons FirstEnergy wants ratepayers to shoulder their burden, include the following trends:

- A precipitous decline in natural gas prices due to the large and growing supply of shale gas and a subsequent decline in the cost of generating power at natural gas-fired power plants.
- Increased competition from renewable wind and solar photovoltaic resources due to steep declines in installation prices and support from federal and state programs.
- Substantial declines in the amounts of power generated at the PPA coal-fired units as that generation has been displaced by less-expensive power from natural gas-fired plants and, in recent years, power from renewable wind and solar resources;
- Sharp declines in energy market prices due, in large part, to the precipitous decline in natural gas prices;
- Relatively flat electric demand in PJM, the regional electricity-transmission organization, and the increased deployment of energy efficiency, demand response, and distributed, on-site renewable resources.
- Volatile capacity market prices and the potential for having to pay substantial penalties under PJM's new capacity performance plan for plants that don't produce when called upon.

- The potential for higher operating costs and/or declining operating performance as W.H. Sammis, Clifty Creek, Kyger Creek and Davis-Besse age.

The Institute for Energy Economics and Financial Analysis finds that:

- FirstEnergy is using greatly inflated forecasts of future natural gas prices and PJM electricity market prices to justify its proposal.
- FirstEnergy's proposal—under an uninflated, reasonable natural gas price outlook—would in truth result in a net cost to ratepayers of approximately $4 billion, rather than the net $561 million gain that the company promises.

IEEFA notes also that this bailout is of a piece with FirstEnergy's larger strategy to "re-regulate" some of its struggling power plants by shifting the costs and risks of those plants to ratepayers while guaranteeing a 10.38% return on equity each year for FirstEnergy and its shareholders on the plants in question.

IEEFA concludes that FirstEnergy proposal is a bad deal for Ohio customers and would lock Ohio into subsidizing the continued operation of aging and uneconomic power plants while hindering opportunities for lower cost and cleaner energy resources that could provide jobs and significant economic benefits for the state.

Finally, IEEFA proposes an alternative to the FirstEnergy bailout plan:

- That rather than propping up these struggling plants, Ohio policymakers work instead for an orderly transition away from outmoded energy generation by supporting the development of cleaner, modern and more efficient resources.
- That the state of Ohio embrace this case as an opportunity to craft an economic-transition plan to support workers and communities that would be affected by the closure of obsolete power plants.

FirstEnergy's service area in Ohio

Part 1: The Proposed PPA and Rider RRS Are a Bad Deal for Customers

FirstEnergy's Ohio retail utilities have proposed what they call a Retail Rate Stability Rider (Rider RRS) through which the costs and risks of three of FirstEnergy's currently deregulated coal-fired plants (Sammis, Clifty Creek and Kyger Creek — "the PPA coal units"—and its deregulated Davis-Besse nuclear plant would be passed on to captive customers of the utilities. These plants were all spun off to a deregulated affiliate created in 2000, when FirstEnergy expected that it would be able to earn substantial profits by selling energy and capacity into the competitive wholesale PJM markets. However, FirstEnergy clearly does not believe that the units are currently profitable. Nor does it believe that expected market conditions will make the units profitable in the coming years, contrary to its utilities' claims that the proposed Rider RRS mechanism will provide a net benefit of $561 million over the eight-year period from June 1, 2016, through May 31, 2024. If FirstEnergy believed that the units could be profitable, it would not be seeking to pass them off to customers through the PPA and Rider RRS.[1]

Under the proposed PPA mechanism, FirstEnergy's regulated utilities in Ohio would become responsible for all of the costs of operating the PPA coal units and the Davis-Besse plant plus the debt costs associated with the units, along with a guaranteed 10.38% return on equity (ROE) each year for FirstEnergy and its shareholders. Those utilities would then receive the revenue generated through the sale of the capacity, energy, and ancillary services provided by the units into the PJM markets. Through Rider RRS, the net costs of operating the plants and the revenues received by selling the capacity, energy, and ancillary services from those plants would then be passed on to customers, who would either pay a charge or receive a credit each year.

This proposal would essentially make customers de facto merchant generators vulnerable to the same significant economic trends and market conditions that have plagued FirstEnergy and other merchant generators in recent years and that have led FirstEnergy to decide that continuing to own and operate the units is not profitable and will not be profitable at any time in the coming years. These economic trends and market conditions include:

- A precipitous decline in natural gas prices beginning in late 2008 and early 2009 due to the large and growing supply of shale gas and a subsequent decline in the cost of generating power at natural gas-fired power plants, as well as the addition of more than eleven thousand megawatts (MW) of new gas-fired capacity in PJM since January 1, 2010 —with thousands more MW of new gas-fired capacity under construction in Ohio and other states;
- Increased competition from renewable wind and solar photovoltaic (PV) resources, as the total megawatts of installed wind and solar capacity have increased due to steep declines in installation prices and support from federal and state programs. This competition is likely to increase in coming years due to continuing declines in installation prices and the recent extension of the solar investment tax credits (ITC) and wind production tax credits (PTC);

1 Throughout this report, we interchangeably refer to Rider RSS as a PPA, or power purchase agreement.

- Substantial declines in the amounts of power generated at the PPA coal-fired units as that generation has been displaced by less-expensive power from natural gas-fired plants and, in recent years, power from renewable wind and solar resources;
- Sharp declines in energy market prices due, in large part, to the precipitous decline in natural gas prices;
- Flat or relatively flat growth in electric demand in PJM, driven by the Great Recession of 2008-2009 and the increased deployment of energy efficiency, demand response, and distributed, on-site renewable resources;
- Volatile capacity market prices and the potential for having to pay substantial penalties under PJM's new Capacity Performance plan for plants that don't produce when called upon.
- The potential for higher operating costs and/or declining operating performance as the PPA coal-fired units age.

While FirstEnergy projects that customers would lose $364 million over the first 31 months of the proposed Rider RRS, it forecasts that customers would receive a net benefit of $561 million over the eight years of the transaction. However, as a result of the above economic trends and market conditions, it is far more probable that customers will be saddled with $4 billion of net charges as they are forced to prop up the uneconomic operation of the PPA coal units through at least May 31, 2024.

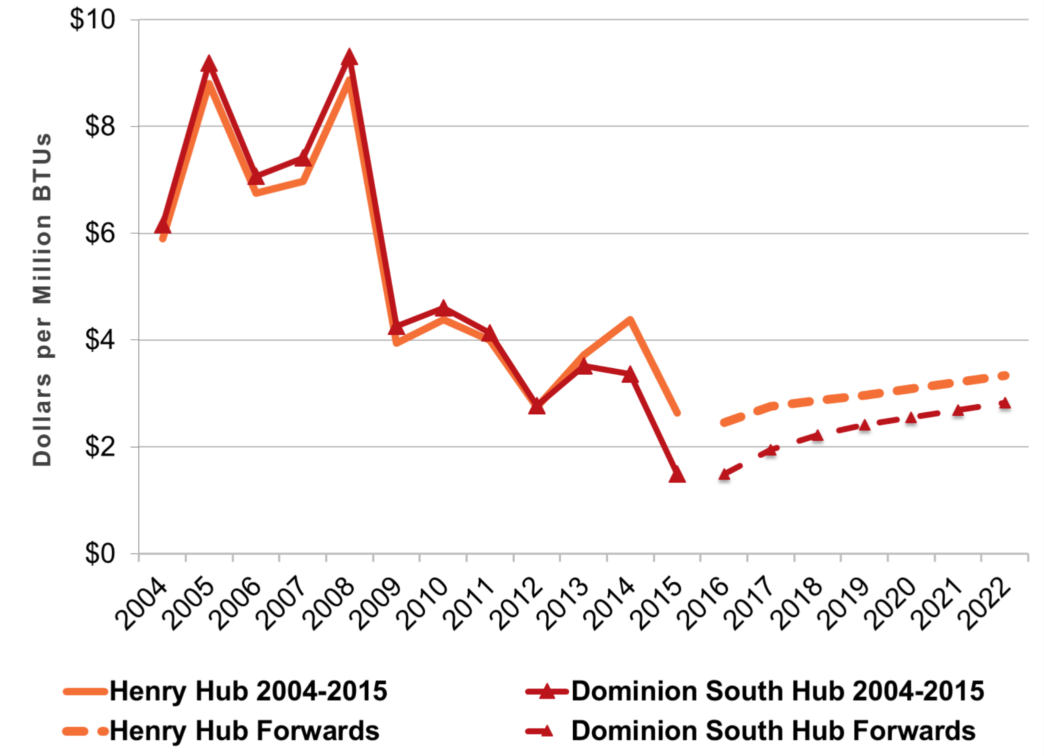
At the same time that customers bear all of the risks associated with the continued operation of the PPA coal units and Davis-Besse, FirstEnergy and its shareholders would be provided a guaranteed 10.38% return on equity every year. Utilities are typically allowed to earn a return on equity above the cost of debt because they are bearing the risks of their operations. Here, FirstEnergy would be bearing none of the risks but seeks a guaranteed profit nevertheless.

A. Natural Gas Prices Declined Precipitously Beginning in Late 2008 and Early 2009

The Henry Hub in Louisiana has traditionally been the most important pricing location for natural gas in the U.S. However, in recent years, the Dominion South Hub in Southwest Pennsylvania has gained in importance due to the discovery and production of increasing amounts of natural gas from the Marcellus Shale in the Eastern U.S.

Figure 1 below shows the historical annual prices for natural gas at the Henry Hub and Dominion South Hubs from 2004 to 2015, as well as the forwards prices for the years 2016 through 2022. The sharp decline between gas prices in 2008 and 2009 is readily apparent.

Figure. 1: Natural Gas Prices at Henry Hub and Dominion South Hub[2]



Although, as shown in Figure 1 above, gas prices rebounded somewhat in 2014, largely due to the polar vortex event in the first months of the year, they again declined quite significantly during 2015. As a result, gas prices fell at Henry Hub by 70 percent between 2008 and 2015 and at Dominion South Hub by 84 percent.[3] According to data from SNL Financial, natural gas prices in PJM fell by 54.3 percent just from November 2014 to November 2015.[4]

Most important, natural gas prices are not expected to rebound significantly at any time in the foreseeable future, as evidenced in the natural gas forwards prices shown in Figure 1. These forward prices represent the prices at which gas can be purchased today for delivery months or years in the future. As such, they represent the market's outlook for future natural gas prices. At both Henry Hub and Dominion South Hub, gas forwards through 2022 sell at or below typical gas prices that the market has seen since the initial price plummet in 2008-09.

Fuel industry and financial community analysts also forecast very slow growth in natural gas prices over the next decade or so. For example, the Oil and Gas Team at UBS Financial recently lowered its 2016-2020 natural gas price forecasts to $2.45, 2.75, $3.00, $3.25, and $3.25 per MMBtu, respectively, from $3.25, $3.75, $4.00, $4.00, and $4.00.[5]

This steep drop in natural gas prices has led to significant declines in the operating costs at gas-fired power plants, which has made them much more competitive against generation at coal-

2 Data on historical natural gas prices derived from SNL Financial. Forward prices from OTC Global Holdings as of January 12, 2015, downloaded from SNL Financial.

3 Id.

4 SNL Financial, Natural gas prices fall faster than power prices YOY to squeeze coal generators, December 2, 2015.

5 *Answers to the Most Frequently Asked Oil and Gas Questions*, UBS Financial, January 12, 2016, available at https://neo.ubs.com/shared/d14j3fKrDiA/.

fired units. And with the low gas prices being projected to continue in coming years, the price of generating power at natural gas-fired plants is not expected to increase significantly. These developments will maintain, and probably even enhance, natural gas's competitive advantage over coal for generating electricity.

B. FirstEnergy's Coal-Fired Plants Face Increased Competition From Renewable Wind and Solar Resources

At the same time that natural gas prices have declined precipitously, there also has been a tremendous increase in the solar- and wind-produced energy on the electric grid, due in large part to steep declines in installation costs, as will be discussed below. The adoption of renewable portfolio standards (RPS) in many states, including some covered by PJM, which typically require utilities to purchase a portion of their power from renewable resources, has contributed to the increase in solar and wind capacity.

The amount of energy generated by wind and solar resources in PJM, as shown in Figures 2 and 3 below, has increased significantly just since 2010.

Figure 2: Wind Energy Generation in PJM[6]

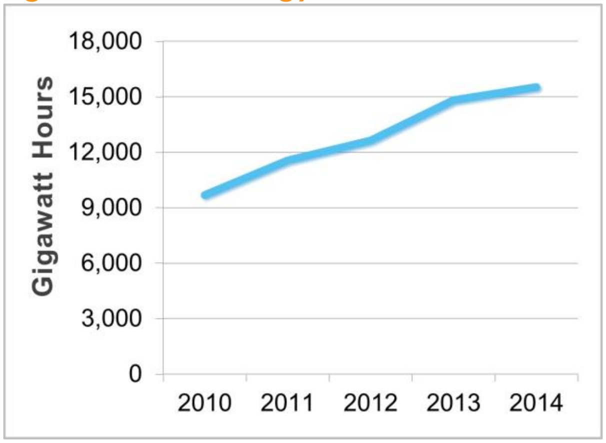
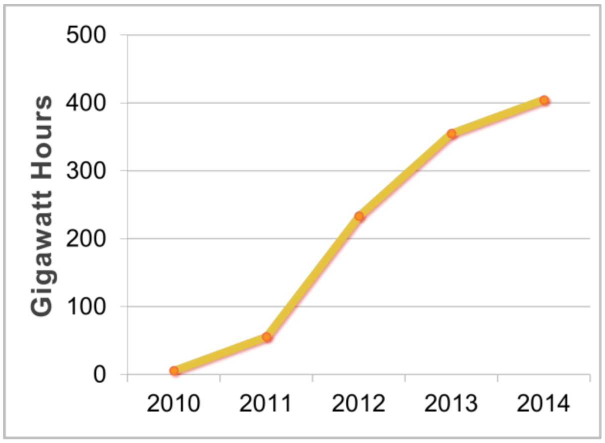


Figure 3: Solar Photovoltaic Generation in PJM[7]



Thus, the amount of energy generated by wind resources in PJM grew by approximately 60% from 2010 to 2014. The amount of energy generated by solar PV resources grew by almost 700%.

This rapid growth in new wind and solar capacity and generation is due to several factors, including declining installation rates, improved operational efficiencies, increased interest in carbon-free resources, and the adoption of renewable portfolio or renewable energy standards by a number of states.

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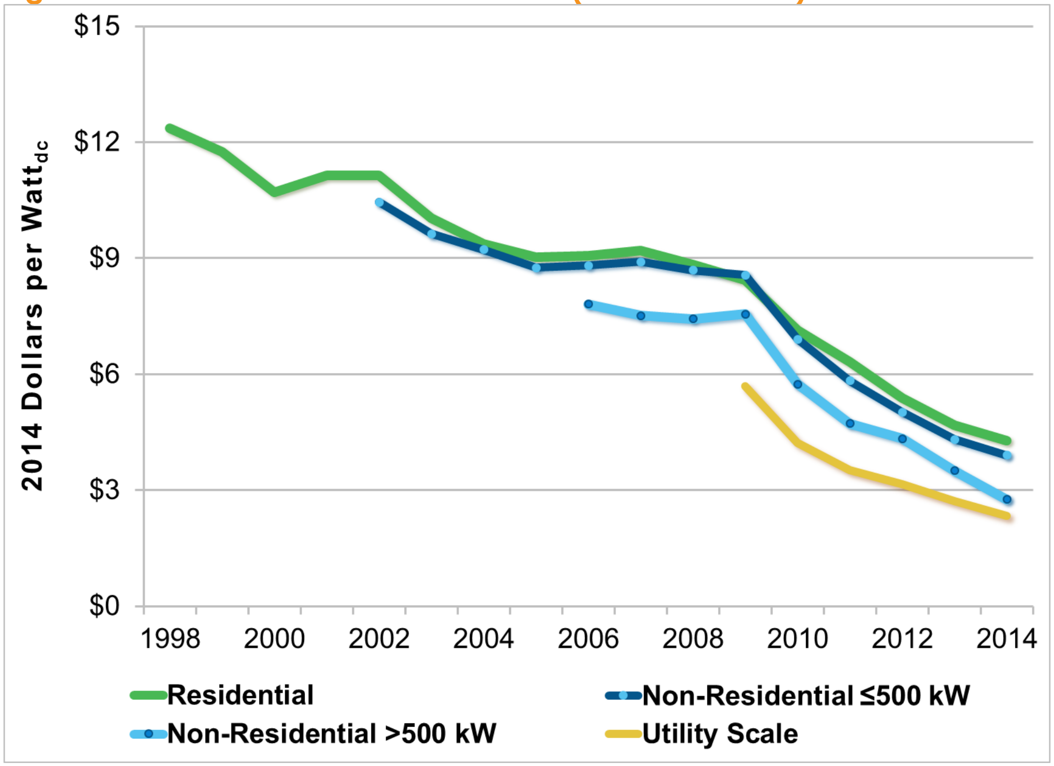
6 PJM State of the Market Reports for 2010 to 2014.

7 Mark Bolinger and Joachim Seel, Lawrence Berkeley Nat'l Laboratory, Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States (Sept. 2015), at Fig. 1, available at https://emp.lbl.gov/publications/utility-scale-solar-2014.

Wind turbine prices have declined substantially in recent years despite increases in hub heights and larger rotor diameters.[8] All of the changes discussed above have combined with improved turbine technology to reduce project costs and wind power purchase agreements prices.[9] As a result, prices for power from wind PPAs have dropped to all-time lows, declining from $70 per megawatt-hour (MWh) for PPAs executed in 2009 to a nationwide average of around $23.50 per MWh for PPAs signed in 2014.[10] During the same year, the levelized annual prices for wind PPAs in the Great Lakes states (which include Ohio) declined from $76.35 per MWh in 2009 to $34.31 per MWh for PPAs executed in 2014.[11] Now that the federal wind Production Tax Credit has been extended for an additional five years, further decreases in wind prices can be expected, putting increased pressure on coal generation.[12]

Installation prices for utility-scale solar projects and for distributed residential and commercial solar PV have also plummeted in recent years. As shown in Figure 4 below, distributed solar PV installation prices decreased by an average of 6 to 8 percent per year from 1998 through 2013, dropping an additional 9 percent from 2013 to 2014. Preliminary data suggest similar price declines in the first half of 2015. Median utility-scale solar PV installation prices have fallen by more than 50 percent from 2007-2009 to 2014.

Figure 4: Solar PV Installation Prices (Median Values)[13]



8 Ryan Wiser, et al., U.S. Department of Energy, *2014 Wind Technologies Market Report* (August 2015), at 29–31, 46–54.

9 *Id.* at 56–60.

10 *Id.* at 56.

11 *Id.*, Figure 46, at p. 57.

12 Christopher Martin and Justin Doom, *Wind Power Without U.S. Subsidy to Become Cheaper Than Gas*, Bloomberg Business (Mar. 12, 2015); *see also* U.S. Dep't of Energy, *WindVision: A New Era for Wind Power in the United States (Executive Summary)* (Mar. 2015).

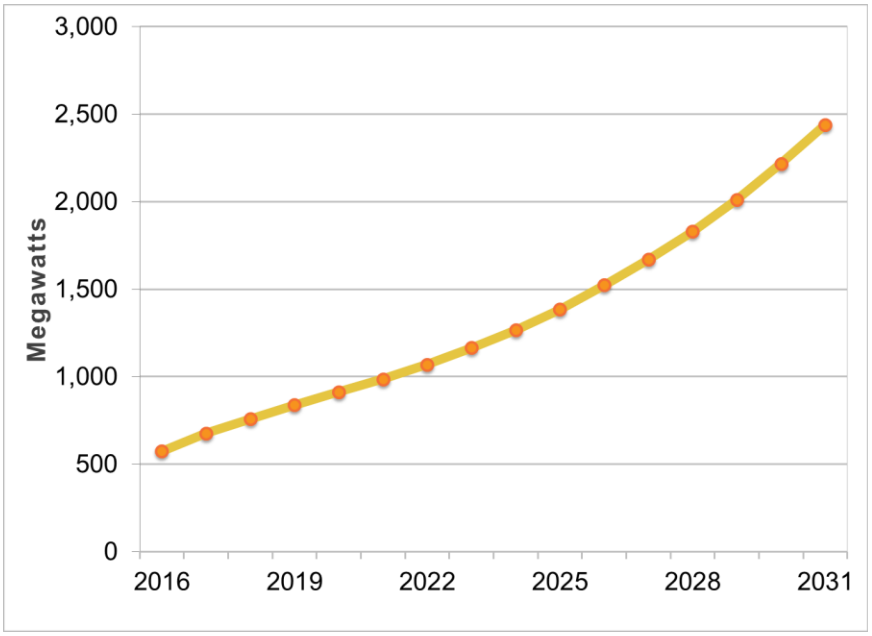
13 Galen L. Barbose, et al., Lawrence Berkeley Nat'l Laboratory, *Tracking the Sun VIII: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2014* (Aug. 2015), at Fig. 7.

Solar installation prices are expected to continue to decline in coming years, with some analysts projecting prices as low as $1.50 to $3 per watt by 2016, with additional declines expected in later years.[14] By comparison, as recently as 2009, median installation prices averaged around $7.50 to $9 per watt, as seen in Figure 4 above.

The prices for long-term PPAs from utility-scale solar PV projects have fallen so dramatically since 2009 that the median PPA price in the U.S. is now just below $50 per MWh, down from over $100 per MWh for PPAs signed as recently as 2010.[15] The combination of declining installation costs and the recent five-year extension of the full solar investment tax credit can be expected to lead to continued growth in the capacity and energy provided by solar PV resources in PJM, a development that will put further downward pressure on the viability of coal-fired units like Sammis, Clifty Creek and Kyger Creek.

In addition to producing electricity that is sold into the grid, distributed solar PV resources also can reduce system demands by generating power that is used on-site. Figure 5 shows that PJM currently forecasts that the reductions in its overall summer peak demand from distributed solar PV resources are already significant and, as additional distributed solar PV resources are installed, will increase by an additional 120% from 574 MW in 2016 to 1267 MW 2024, the currently proposed end of FirstEnergy's PPA rate mechanism.[16] And the increasing deployment of distributed solar PV resources is forecast to reduce summer peak demands by more than 2400 MW in 2031. These reductions in demands due to solar PV resources will put downward pressure on energy and capacity market prices and, consequently, will reduce the revenues that customers can expect to earn from selling into the PJM markets the energy and capacity of the PPA coal-fired units and the Davis-Besse nuclear plant.

Figure 5: PJM Forecast of Increased Distributed Solar PV Resources



[14] David Feldman, et al., Nat'l Renewable Energy Laboratory and the Lawrence Berkeley Nat'l Laboratory, *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections, 2014 Edition* (Sept. 22, 2014), at slides 5 and 26-28, *available at* http://www.nrel.gov/docs/fy14osti/62558.pdf.

[15] Bolinger, *supra* n. 7, at 33, 35, and 37.

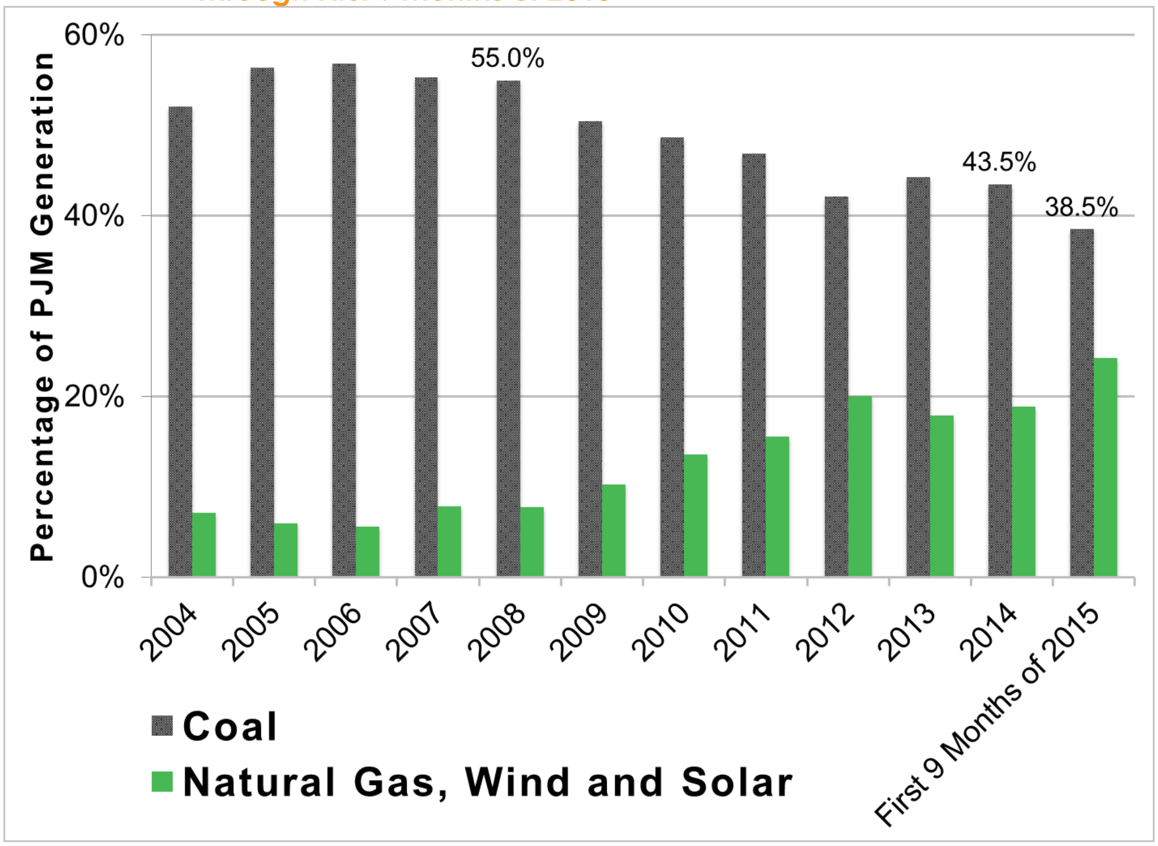
[16] PJM January 2016 Load Forecast Report, Table B-8, at page 71.

C. Generation at Coal-Fired Power Plants Has Declined Steeply As a Result of Low Natural Gas Prices and the Addition of More Renewable Wind and Solar Capacity

In recent years, low natural gas prices have allowed natural gas-fired power plants to reduce their operating costs and to displace coal as the marginal fuel for many hours of the year in wholesale energy markets nationwide. For example, as shown in Figure 6, below, the substantial drop in natural gas prices beginning in late 2008 and early 2009 reinforced more recently by a surge of new renewable resources, has driven down the amount of power generated from coal in PJM quite significantly. And at the same time that coal usage has been declining, the percentages of electric generation in PJM from natural gas and non-hydro renewable resources have been increasing significantly.

As shown in Figure 6 below, coal-fired generation dropped from 55.0 percent of total electric generation in PJM in 2008 to 43.5 percent in 2014 and to 38.5 percent in the first three-quarters of 2015.

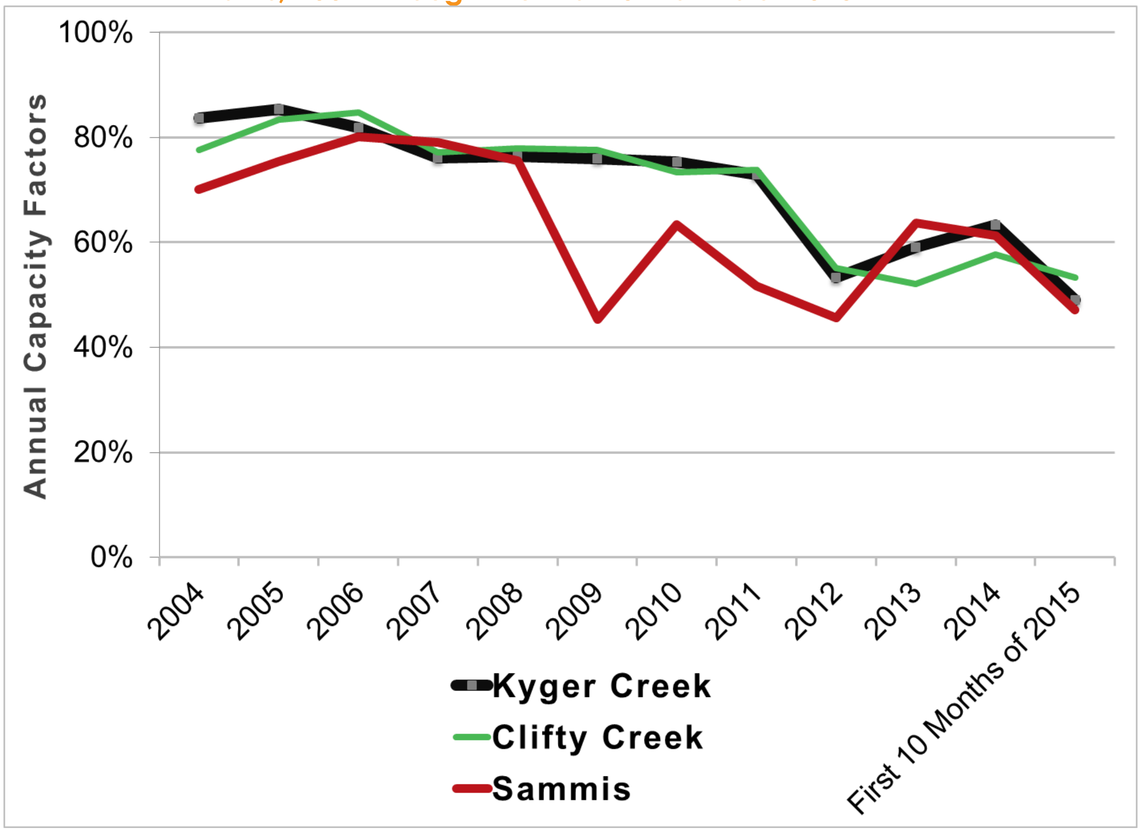
Figure 6: PJM Generation by Fuel Source – Coal Versus Natural Gas, Wind and Solar, 2004 Through First 9 Months of 2015[17]



[17] *State of the Market Reports for PJM for the Years 2004-Third Quarter of 2015,* available at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/.

The industry metric "capacity factor" compares how much power a power plant actually generates in a specific time period, such as a month or a year, with how much power the plant would have produced if it had operated at its full capacity for all of the hours in the time period. Figure 7, below, shows the annual capacity factors of the PPA coal units, with clear declines beginning around 2006 for Clifty Creek and Kyger Creek and in 2009 for Sammis.

Figure 7: Annual Generation at Sammis, Clifty Creek and Kyger Creek Coal-Fired Power Plants, 2004 Through the First 10 Months of 2015[18]



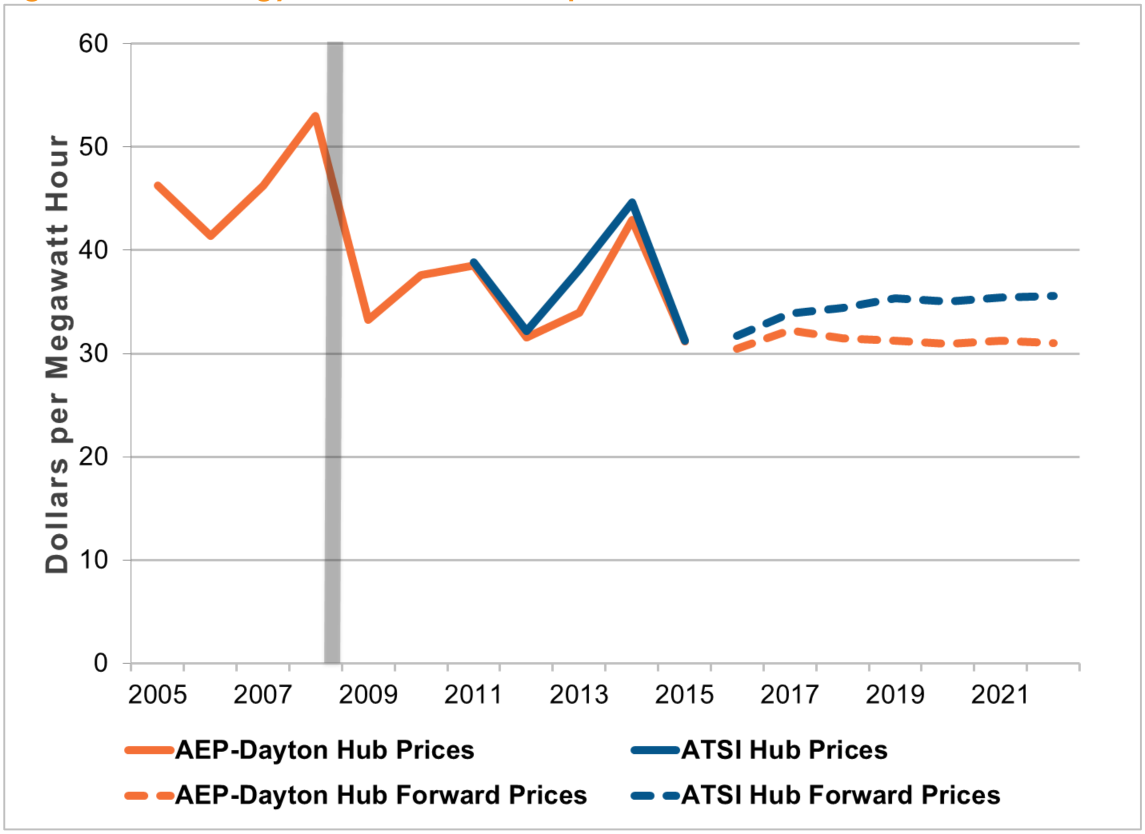
Thus, the total generation of the three coal plants declined by 22 percent from 30 million MWh in 2008 to 23.5 million MWh in 2014. And with the units' significantly lower capacity factors in the first 10 months of 2015, their total generation that year will probably be much lower still. Moreover, and most importantly, there is no reason to expect that these three coal-fired units will regain the generation they have lost since 2008 given that natural gas prices are expected to remain very low for the foreseeable future and that additional wind and solar PV resources can be expected to be added in the coming years. In fact, given the expected low gas prices and the increased development of less expensive renewable resources, the generation from existing coal-fired units in PJM, including Sammis, Clifty Creek, and Kyger Creek, can be expected to decline further, a decline that will further undermine their viability for years, if not permanently.

18 Coal plant capacity factors from SNL Financial with the information originally taken from EIA Form 923 Filings. Forward prices from OTC Global Holdings as of January 12, 2015, downloaded from SNL Financial.

D. The Precipitous Decline in Natural Gas Prices in 2008-2009 Has Led to a Steep Decline in Wholesale Electricity Prices

At the same time that coal-fired electricity generation has declined substantially, wholesale electricity prices in PJM have declined as a result of low natural gas prices, relatively flat loads, and increased generation from renewable wind and solar resources. This can be seen clearly in Figure 8 below, which depicts power prices at the ATSI and AEP-Dayton Hubs in PJM.

Figure 8: Energy Market Prices in Representative Wholesale Markets, 2005-2022[19]



The vertical line in Figure 8 represents the period in late 2008/early 2009 when natural gas prices began to decline precipitously. It is clear that energy market prices decline significantly following the decline in natural gas prices.

Because natural gas prices determine the clearing prices in wholesale energy markets during many hours of the year (i.e., the price that *all* generators receive when they sell power into the

[19] Data for this chart derived from SNL Financial.

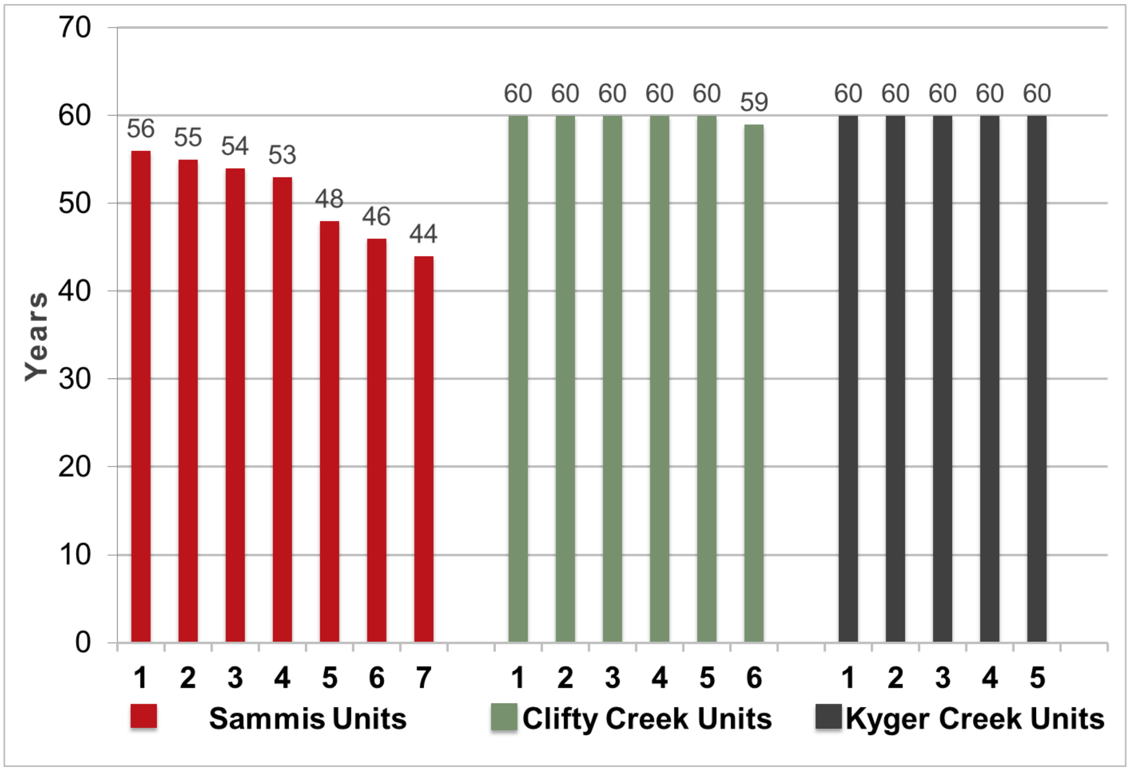
market during the hour) and gas prices are expected to remain low, energy market prices are expected to remain low for the foreseeable future, as Figure 8 indicates.

The combination of low market prices and reduced generation will severely limit the revenues that customers can expect to receive from selling the energy from the Sammis, Clifty Creek, and Kyger Creek coal-fired plants into the PJM energy market.

E. The Sammis, Clifty Creek and Kyger Creek Coal-Fired Units are Aging

As shown in Figure 9 below, none of the units at the Sammis, Clifty Creek and Kyger Creek plants is young. The units at Clifty Creek and Kyger Creek average 60 years old. The units at the Sammis plant are from 44 to 56 years old.

Figure 9: The Age of the Units at the Sammis, Clifty Creek and Kyger Creek Coal-Fired Power Plants



Babcock & Wilcox, an experienced designer and builder of fossil fuel-fired and nuclear power plants, including coal-fired plants, has identified the consequences of plant aging as follows:

> "At the beginning of power plant life there is a period in which the operators and maintenance crews learn to work with the new system and minor problems are resolved. This period may be marked with a high forced outage rate, but this quickly declines as the system is broken in.

As the plant matures, the personnel adapt to the new system, and any shortcomings are overcome or better understood. During this phase the forced outage rate remains low, availability is high, and the operating and maintenance costs are minimal. This mature phase normally lasts 25 to 30 years, depending on the design and use of the unit. The power plant is usually operated near rated capacity during this period.

> Following this phase, the aging process becomes noticeable. Forced outages and maintenance costs increase and availability declines. Component end of life usually causes the higher forced outage rate. Occasional operational error and the degradation of boiler components due to erosion, corrosion, creep and fatigue lead to localized failures. The forced outage rate steadily increases during this phase unless major overhauls or component replacements are instituted."[20]

Babcock & Wilcox adds this on how the role of aging plants evolves:

> "Newer, more reliable plants are less costly to maintain and are generally more efficient to handle the base power load. The older plants become auxiliary units or are designated for peaking service. Older plants with higher heat rates, i.e., lower efficiencies, or with low capacity may be retired. Prior to the 1980s, it was assumed that older plants would be torn down to make room for the newer, larger, more efficient units. It was common to retire a plant after 35 to 40 years of service.

> This planned obsolescence began to change in the early 1980s. The cost of newer, more efficient plants became more than most boiler operators could readily finance. As a result, new construction was delayed and plans to retire the older plants were put on hold. The need to keep the older units running brought about a new strategy of *life extension*. This is a strategy that delays the plant retirement while maintaining acceptable availability. The strategy requires the replacement of some components to keep the plant running with acceptable forced outage rates and maintenance costs. These replacements or repairs expand upon those traditionally incorporated in a plant maintenance program. Significant capital expenditures are normally required to affect the availability rate."[21]

It is reasonable, then, to expect that the Sammis, Clifty Creek, and Kyger Creek coal-fired plants will face unfavorable economics in coming years resulting from (a) higher annual operating and maintenance costs as they age; (b) the need for additional capital investments as they age; and (c) degradation in their operating performance as they age, in terms of lower net generation and higher planned and forced outage rates. In conjunction with the availability and cost of lower cost natural gas and renewable wind and solar resources, these factors will undermine the future viability of the plants and the benefits that could be expected from the sale of their energy, capacity, and ancillary services into the PJM markets.

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20 Babcock & Wilcox, Steam, Its Generation and Use, 40th Edition, (1992), Chapter 46, at 46-1 et seq.
21 *See id.* at 46-1 and 46-2.

F. Customers Cannot Depend on Future Growth in the Demand for Electricity as the Basis for Any Significant Increases in Power Plant Generation and Revenues from the PPA Coal and Nuclear Units

The amount of electricity used in PJM has been relatively flat since 2004, as shown in Figure 10. In fact, the annual energy usage in 2014 was almost precisely the same as it had been in 2004.

Summer peak demands have shown some year-to-year swings, as shown in the solid line in Figure 11 below. However, when the effects of weather are normalized, the summer peak demands have been relatively flat, as well, as can be seen from the dashed line in Figure 11.

In fact, the actual peak demand in the summer of 2015 was only slightly above the actual peak in the summer of 1999.

This relatively flat growth in electric demands in PJM (both energy and peak) stems from the Great Recession of 2008-2009 and from the increased deployment of energy efficiency and distributed, on-site renewable resources.

Figure 10: PJM Annual Net Energy, 1999-2014[22]

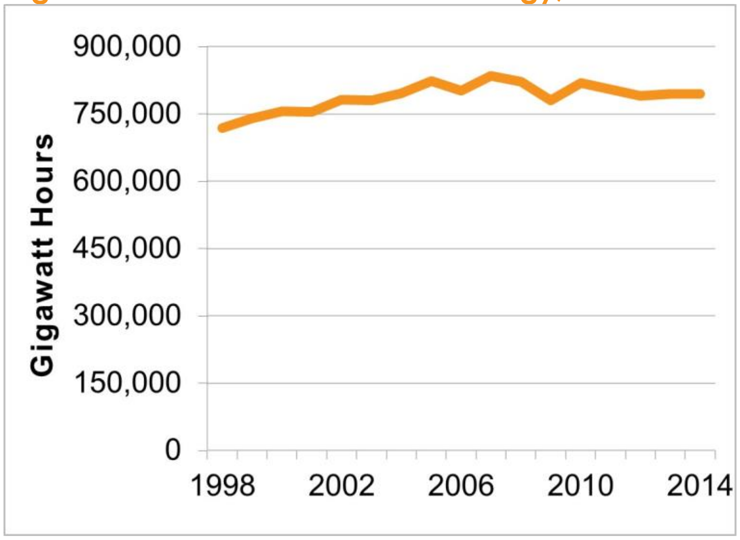
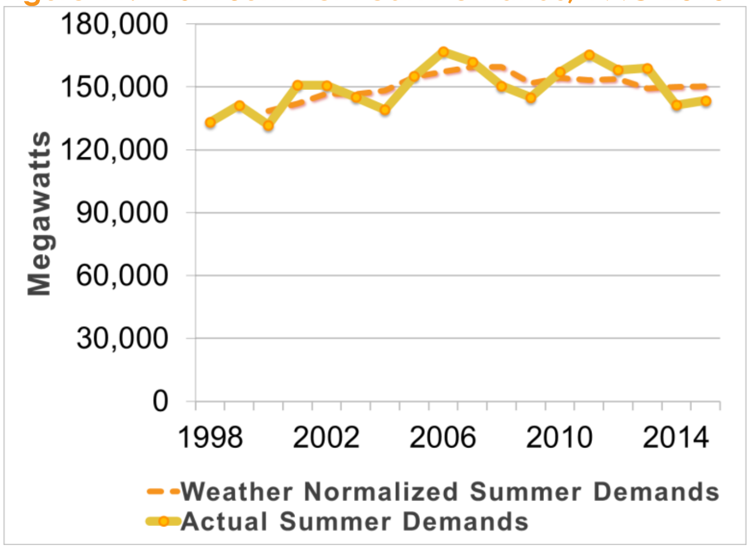


Figure 11: PJM Summer Peak Demands, 1998-2015[23]



22 PJM 2016 Load Forecast Report, Tables F-1 and F-2, on pages 88-89 and 93-94.

23 PJM 2016 Load Forecast Report, Tables F-1 and F-2, on pages 88-89 and 93-94.

PJM forecasts of future summer peak demands and energy usage also have been declining in recent years, as shown in Figures 12 and 13 below.

Figure 12: PJM 2014-2016 Forecasts of Future Summer Peak Demands[24]

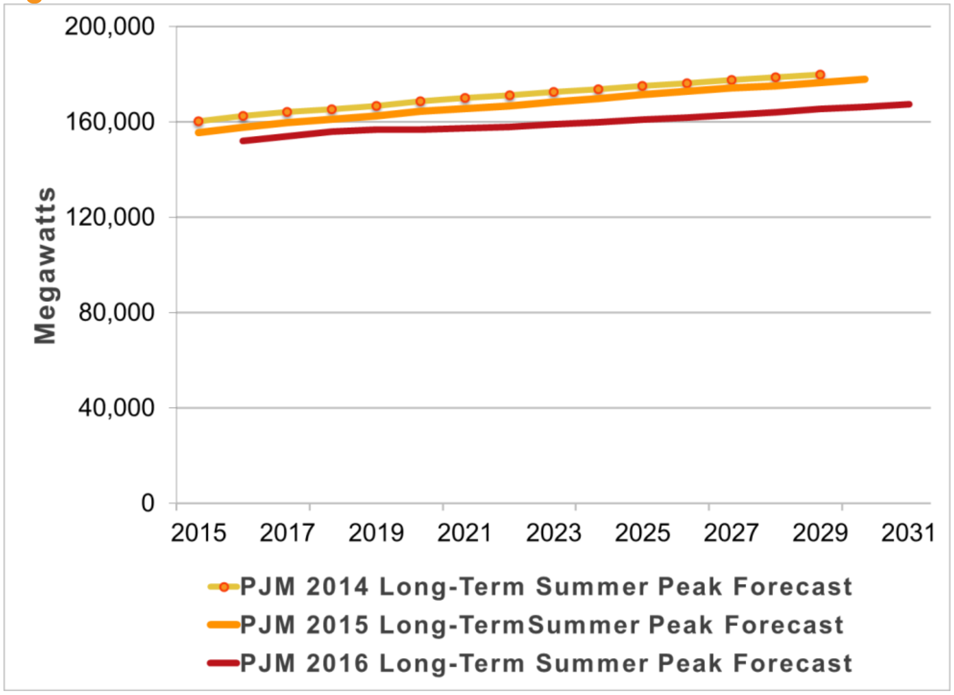
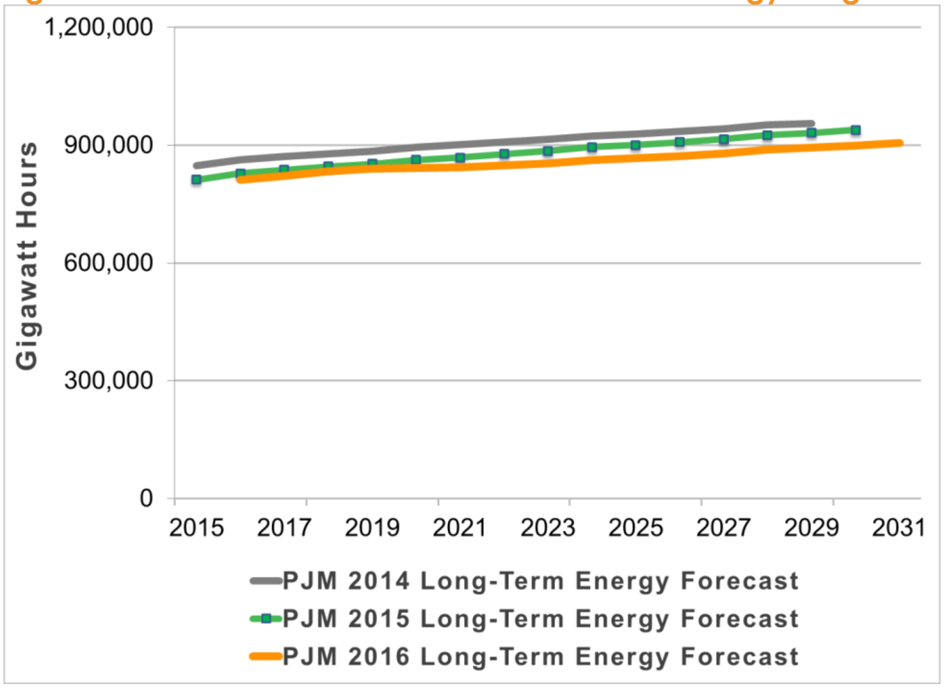


Figure 13: PJM 2014-2016 Forecasts of Future Energy Usage[25]



24 PJM 2014, 2015 and 2016 Load Forecast Reports.
25 PJM 2014, 2015, and 2016 Load Forecast Reports.

The methodology used to develop PJM's 2016 load forecasts was revised in several ways to reflect the fact that in previous years PJM significantly over-estimated its future loads. Compared to PJM's 2015 load Report, the 2016 PJM forecast shows a number of substantial reductions in projected summer peak demands:

- The 2016 summer peak is projected to be 5,781 MW (3.7%) lower.
- The 2019 summer peak is projected to be 5,660 MW (3.5%) lower.
- The 2021 summer peak is projected to be 8.406 MW (5.1%) lower.
- The 2024 summer peak is projected to be 9,715 MW (5.7%) lower.

PJM's 2016 annual energy forecasts for 2016 through 2024 are also 1.5% to 3.6% lower than its forecasts had been in 2015, as can be seen from Figure 13. These lower peak demand and energy usage forecasts reduce the need for the capacity and energy from the PPA coal and nuclear units. They also likely will lead to lower energy and capacity market prices, other things being equal.

At the same time that the need for the capacity and energy from the PPA coal and nuclear units has been declining, new generating capacity (natural gas, wind and solar) is under construction or being proposed that will compete with the Sammis, Clifty Creek, Kyger Creek, and Davis-Besse plants in the wholesale PJM markets.

For example, low natural gas prices are attracting new natural gas generation in Ohio that is expected to be on-line by 2020:

- Three new gas plants representing a total of over 2,000 MW of capacity are under construction (Oregon Clean Energy Center, Carroll County Energy Generation Facility, and the Middletown Energy Center) and expected to be in operation by 2018.
- Another 800 MW of capacity has been approved by the Ohio Power Siting Board (Clean Energy Future – Lordstown) and another 1,100 MW facility (South Field Energy Electric Generation Facility) is being proposed.

In fact, Ohio regulators have told state lawmakers that they expect 4,300 MW of new natural gas-fired electric generating capacity to be on-line by 2019.[26]

The addition of this new capacity (burning low-cost natural gas) and whatever new wind and solar capacity is installed will (1) alleviate concerns that closure of the Sammis and Davis-Besse plants would adversely impact electric grid reliability in Ohio and (2) will compete with those units if they are not closed. This will mean continued low energy market prices, reduced generation at the Sammis, Clifty Creek, and Kyger Creek coal-fired plants, and much lower revenues for customers under the PPA proposal.

Moreover, independent power producer Dynegy has just offered to expand the capacity of its five existing Ohio power plants in order to replace the power that would be provided by FirstEnergy's Sammis and Davis-Besse plants and by nine units owned by American Electric Power.[27] According to Dynegy, its proposal would save FirstEnergy's Ohio consumers and business $2.5 billion and AEP's consumers and businesses another $2.5 billion over the eight-year

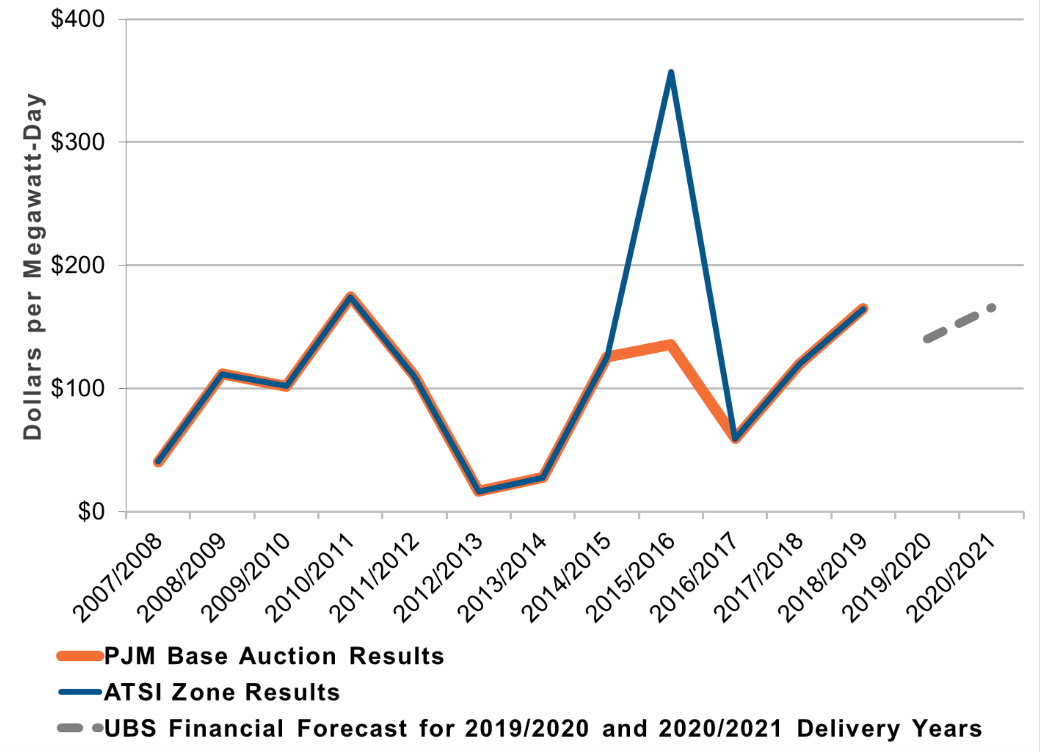
[26] Funk, "New power plants using Ohio gas could replace FirstEnergy's old coal and nuclear," *Plain Dealer*, Jan. 16 2016.
[27] Id.

term of the proposed contracts.[28] Exelon Generation also has offered an alternative proposal that it says will provide well over $2 billion in savings to Ohio families and businesses "as compared to the grossly lopsided deal offered by FirstEnergy.[29]

G. Volatile Capacity Market Prices and the Potential for Having to Pay Substantial Penalties under PJM's new Capacity Performance Plan Pose Significant Risks for Customers under FirstEnergy's PPA and Rider RRS Proposal

Each year PJM conducts a base auction for capacity prices that would be in effect during a delivery year three years in the future. For example, in 2015 PJM conducted base auctions for capacity to be delivered from June 1, 2018 to May 31, 2019. As can be seen in Figure 14, below, the capacity prices resulting from these auctions have been extremely volatile since the first auction was held for the 2007/2008 delivery year. As can be seen, capacity prices have bounced up and down.

Figure 14: PJM Capacity Prices[30]



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28 Id.

29 Second Supplemental Testimony of Lael Campbell on behalf of Constellation Newenergy, Inc. and Exelon Generation Company, LLC, December 30, 2015, at page 2, lines 3-7.

30 PJM 2018/2019 RPM Base Residual Auction Results, available at http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2018-2019-base-residual-auction-report.ashx.

Prices were higher in the most recent PJM auction (conducted in 2015 for the 2018/2019 delivery year) because PJM is in the process of implementing a Capacity Performance plan under which generators would be compensated if their plants are able to produce power when called upon during extreme conditions and penalized if their plants do not performed reliably when called upon. And the penalty that a generator could be forced to pay could exceed the total of the capacity payments it would be receiving through the capacity auction for that year. This would create a significant risk for customers under the PPA proposal in that they would have to pay if any of the plants for which they would be liable don't operate reliably when called upon by PJM to generate.

H. FirstEnergy Has Distorted the Benefit of its Proposed PPA and Rider RRS

FirstEnergy is claiming that its revised PPA and Rider RRS proposal will produce $561 million in benefits (that is, higher market revenues than plant costs) during the eight-year period from June 1, 2016, through May 31, 2024. However, FirstEnergy has failed to make public the calculations and most of the important assumptions underlying this claimed $561 million in benefits. Such lack of transparency hinders the ability of the public to fully assess the reasonableness of FirstEnergy's assumptions and projections. Nevertheless, it does appear from the public testimony filed by parties to the Public Utilities Commission of Ohio proceeding opposing FirstEnergy's PPA proposal that the company has assumed very high natural gas prices, energy market prices, and levels of generation from the PPA coal plants and Davis-Besse that are unlikely to materialize.

FirstEnergy's natural gas price forecast, developed in 2014, projected that natural gas prices would be $4.34 per MMBtu in 2015 and $4.28 per MMBtu in 2016. Table 1, below, shows that these projected prices were much higher than actual natural gas prices in 2015 and are far above current forwards prices for 2016.

Table 1: FirstEnergy Projected Natural Gas Prices Versus 2015 Actual Prices and 2016 Forward Prices

Year	First Energy Projected	Actual Price 2015/ Current Forward Price 2016
2015	$4.34	$2.63
2016	$4.28	$2.45

Using such high natural gas prices, on its own, will completely distort FirstEnergy's analysis of its PPA proposal, in large part because they result in unreasonably high energy market prices.

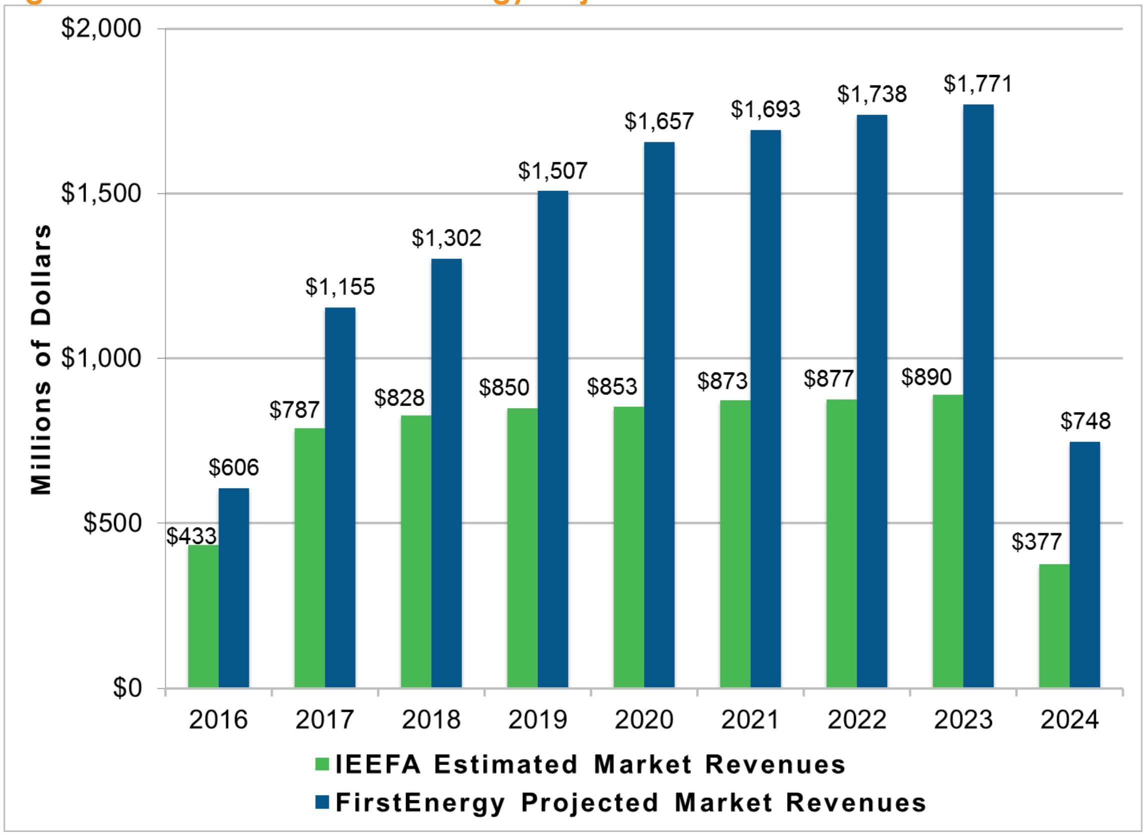
In addition, it is clear that FirstEnergy used PJM's 2014 load forecasts in its analysis. As shown in Figures 12 and 13, PJM's recent 2016 forecasts are significantly lower than its 2014 forecasts. For example, PJM's 2016 energy usage forecasts for the years 2016-2024 are approximately 6% lower than its 2014 forecasts were and its 2016 peak demand forecasts are approximately 6% to 8% lower. Using PJM's new and lower load forecasts, in turn, will reduce the expected generation from the PPA coal and nuclear units, as well as lowering the market revenues that customers could expect from selling the units' capacity and energy into the PJM markets.

IEEFA has prepared alternative forecasts of both the market revenues that could be expected from selling the PPA units' energy, capacity, and ancillary services and the costs associated with the PPA units. These alternative forecasts are based on the following conservative assumptions:

- From June 1, 2016 through May 31, 2024, each of the PPA coal and nuclear units will generate the average amount of power it produced annually during the five-year period from 2010-2014;
- Energy market prices are based on current forwards prices[31] through 2022 and escalated at a 2% annual rate in 2023 and 2024;
- Capacity prices will reflect the already determined prices during the 2016/2017, 2017/2018, and 2018/2019 delivery years and the UBS Financial forecasts for the 2019/2020 and 2020/2021 delivery years.[32] Capacity prices for subsequent years would remain at the $166 per MW-day figure assumed for the 2020/2021delivery year.

The results of IEEFA's alternative forecast of potential market revenues are presented in Figure 15 below, and compared with FirstEnergy's claimed market revenues for the PPA units.

Figure 15: IEEFA Versus FirstEnergy Projections of Market Revenues



31 As of January 12, 2016.

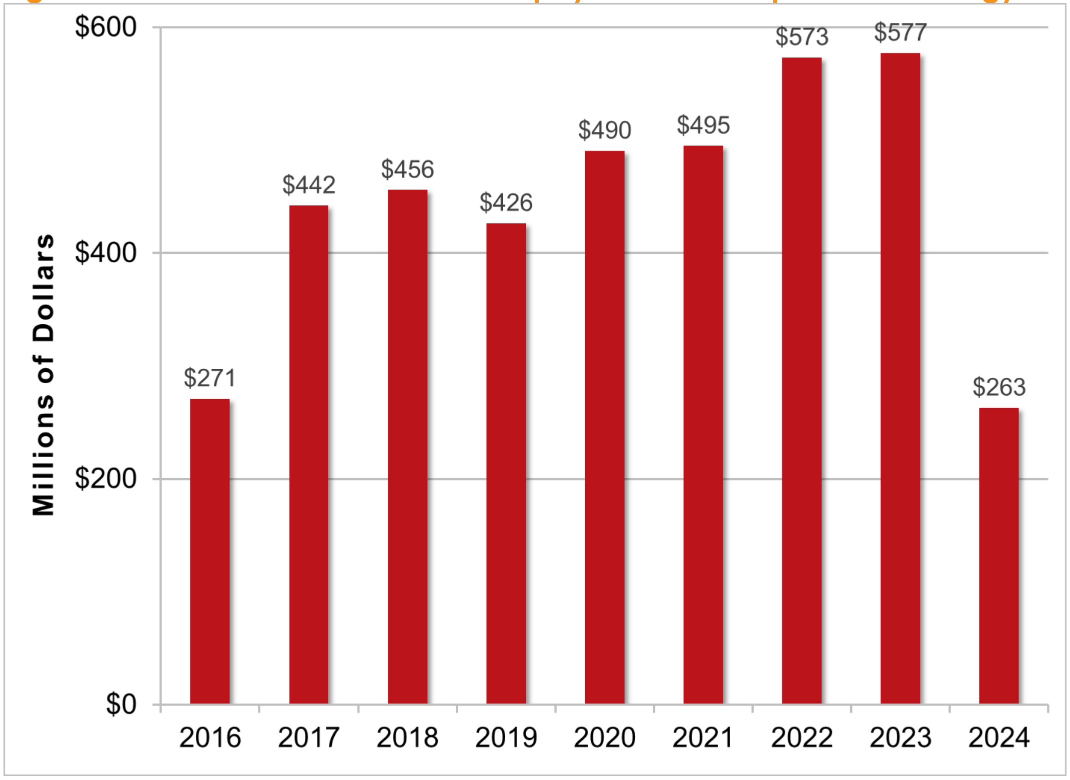
32 See Figure 14, above.

In total, IEEFA estimates that customers would earn approximately $6.8 billion in market revenues from selling the energy, capacity and ancillary services from the three PPA coal units and Davis-Besse during the eight year PPA period. This is approximately $5.4 billion lower than the $12.2 billion in market revenues claimed by FirstEnergy.

IEEFA also adjusted FirstEnergy's projected costs of operating the PPA coal units and Davis-Besse because it appears that FirstEnergy has unreasonably assumed that these units (or even some of them) will generate significantly more energy in coming years than they have in recent years.[33] For the reasons outlined in the previous sections of this report, especially continued low natural gas prices and the building of additional efficient natural gas-fired combined cycle generating capacity in Ohio and elsewhere in PJM, it is far more reasonable to expect that the generation from the PPA coal units, in particular, will continue to decline rather than increase.

After IEEFA's adjusted costs of operating the units are deducted from our adjusted projected revenues, the analysis shows that what FirstEnergy claims would be a $561 million savings for customers from the PPA proposal turns into an approximate $4 billion cost to consumers, as shown in Figure 16 below.

Figure 16: The Annual Cost to Ratepayers of the Proposed FirstEnergy PPA



33 FirstEnergy has not made public the projected capacity factors for the PPA coal units and Davis-Besse that underlie its analysis of the proposed PPA. However, based on other regulatory filings, IEEFA assumes that FirstEnergy has used a 75 percent average annual capacity factor for the Sammis 6 and 7 supercritical coal-fired units and a 65 percent average annual capacity factor for the remaining PPA coal units. IEEFA also has assumed, based on the operation of other nuclear plants, that FirstEnergy has used a 90 percent average annual capacity factor for the Davis-Besse plant in its analysis of the proposed PPA. If FirstEnergy has assumed lower capacity factors than these for any of these PPA units, the annual costs shown in Figure 16 would be larger and the total cost to customers would be even higher than the $4 billion calculated by IEEFA.

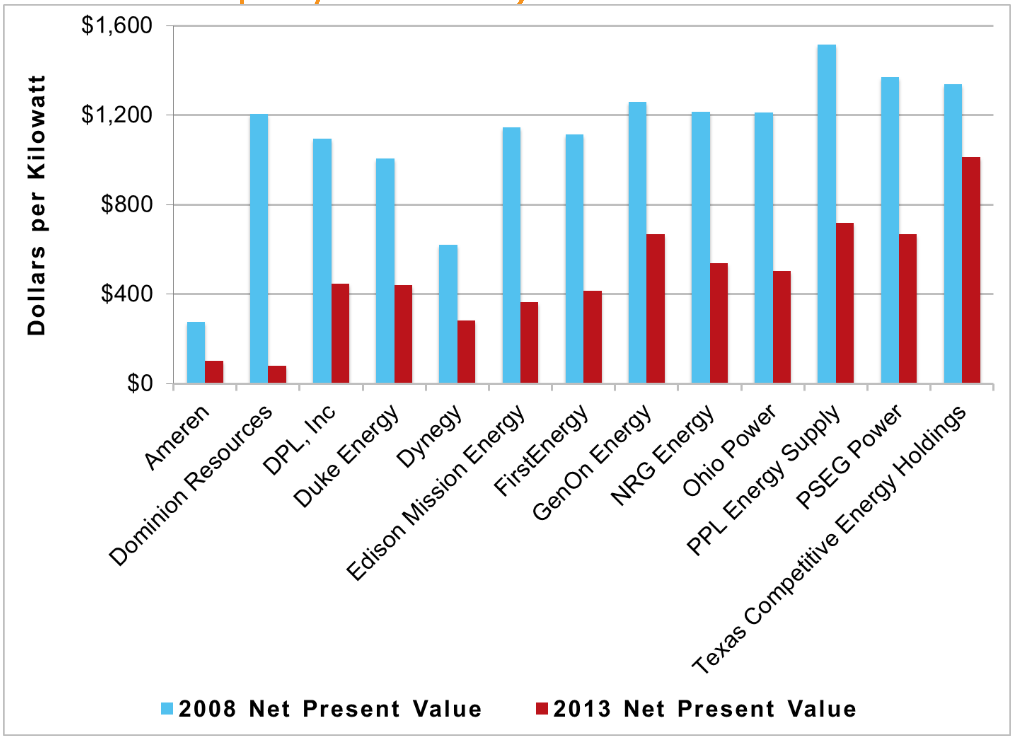
In every year, the costs under the proposed PPA would be higher than the market revenues that could be obtained by selling the energy, capacity and ancillary services from the PPA coal units and Davis-Besse into the PJM markets—in other words, a net charge would be passed through the Rider RRS to customers in each year. Overall, the PPA and the Rider RRS would result in a net $4 billion cost to customers.

Moreover, our analysis is conservative in that the actual generation of the PPA coal units and Davis-Besse might actually be lower in coming years than IEEFA has assumed or PJM energy and/or capacity market prices might be significantly lower. The costs to customers could be significantly more than $4 billion if any of these circumstances actually come to pass.

I. The Financial Value of Domestic U.S. Coal-Fired Power Plant Fleets Has Declined Significantly Since 2008

The fundamental market forces and factors we have discussed in this report are applicable to other merchant-owned coal plants in the U.S. and have led to dramatic declines in the values of many domestic U.S. coal fleets between 2008 and 2013. Figures 17a and 17b, based on an analysis by FitchRatings,[34] display these trends.

Figure. 17a: Declines in Coal Fleet Valuations (Net Present Value, in Dollars Per Kilowatt of Capacity in Each Fleet) From 2008 to 2013[35]



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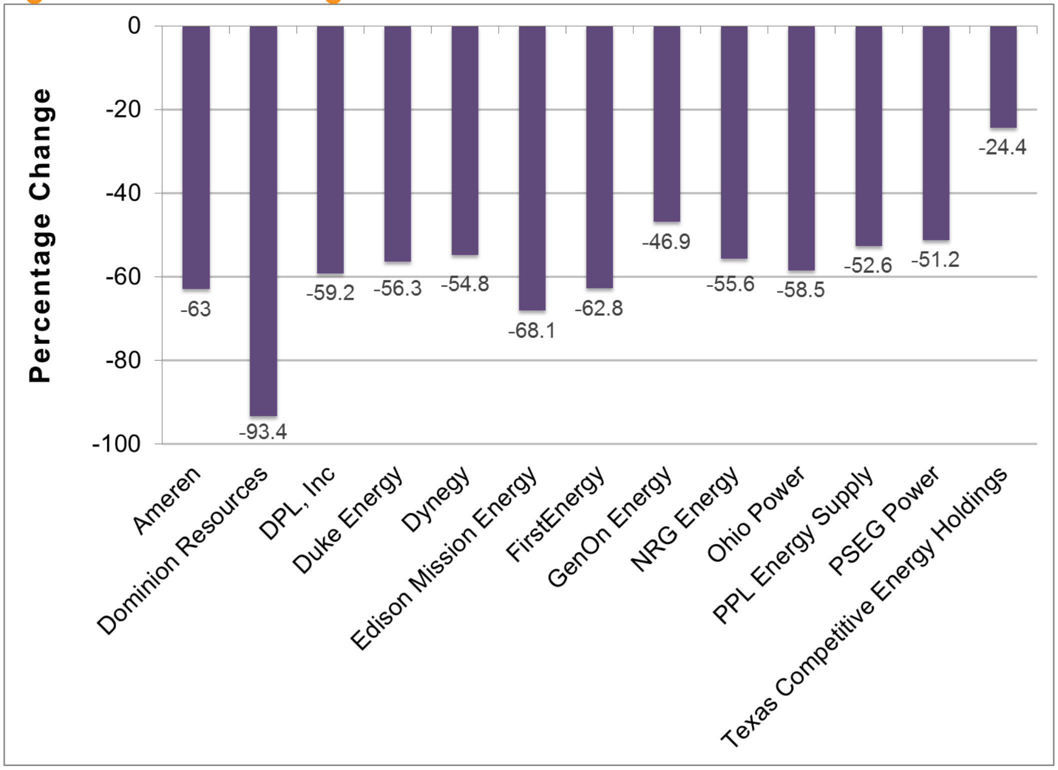
[34] Fitch Ratings, *The Erosion in Power Plant Valuations* (Sept. 25, 2013), *available at* www.fitchratings.com.
[35] Id.

Figure 17b: Percentage Declines in Coal Fleet Valuations From 2008 to 2013[36]



The market for merchant coal-fired power plants is essentially in free fall. Dynegy bought the Danskammer plant in Newburgh, N.Y. (along with a partial share of the Roseton plant) for $900 million in 2001.[37] When the plant was resold in 2013, its value had plummeted to $3.5 million.[38] Dominion Resources sold its 1600 MW Brayton Point coal plant in Southeastern Massachusetts for an estimated $55 million in 2013,[39] shortly after spending $1 billion to complete capital upgrades on the plant.[40] One month after acquiring the plant, the new owner announced a decision to retire Brayton Point in 2017.[41]

Declining coal fleet values are more evidence that ownership of the PPA coal-fired units would be risky and uneconomic for customers as there is no reason to believe that the same market forces and conditions that have reduced the value of other coal plants will not apply to the Sammis, Clifty Creek, and Kyger Creek coal-fired units and to FirstEnergy's plan to transfer the costs and risks of those plants to customers.

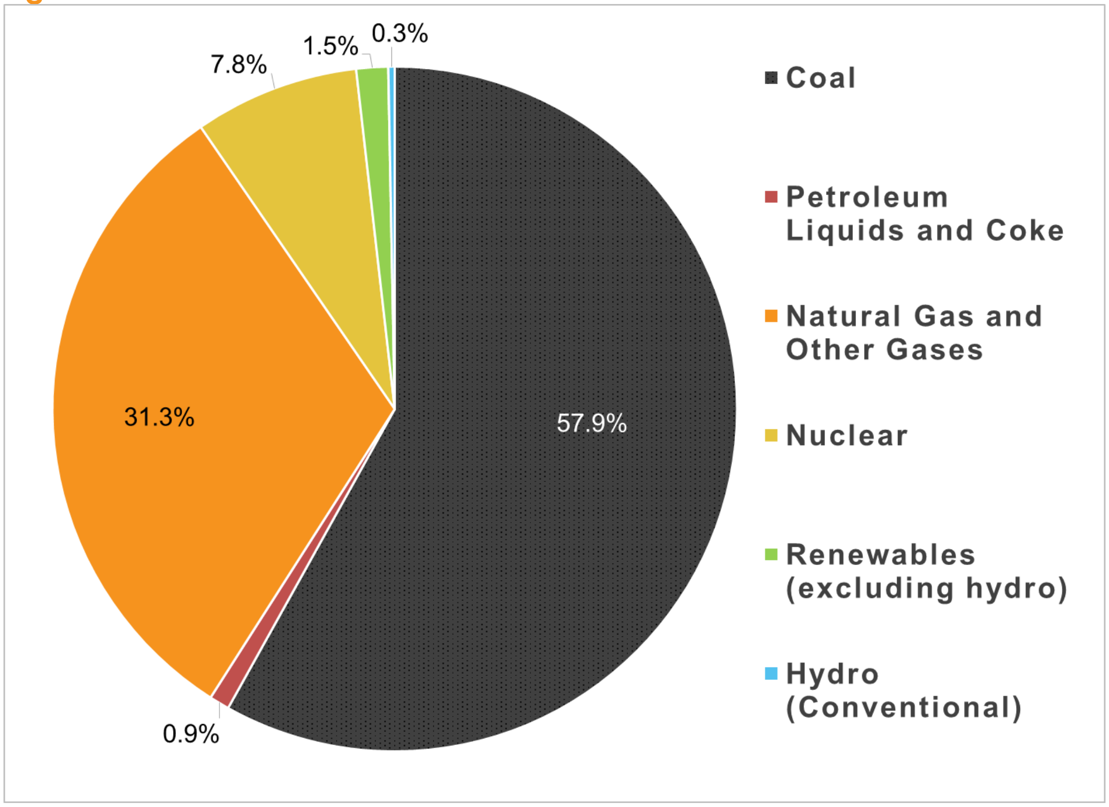
36 *Id.*
37 *Central Hudson closes sale on Roseton and Danskammer generating plants*, Power Engineering (Feb. 2, 2001).
38 *Dynegy Announces Results of Roseton and Danskammer Auction*, BusinessWire (Dec. 10, 2012).
39 Joe C. Goode, *Somerset's Brayton Point power station sold to private equity firm*, The Herald News (Mar. 11, 2013). Brayton Point was sold in a package deal with two other power plants that was projected to result in after-tax proceeds of approximately $650 million. Although Dominion did not publicize the specific sale price of Brayton Point, analysts have estimated its value to have been approximately $55 million at the time of the sale. *See* Institute for Energy Economics and Financial Analysis, Press Release, *Connecticut's Last Coal-Fired Power Plant Is in Critical Financial Condition, Community Needs to Plan for Transition* (Jan. 23, 2014).
40 *See* Steve Urbon, *Brayton Point to shut down as of June 2017,* South Coast Today (discussing capital expenditures at Brayton Point) (Oct. 7, 2013), *available at* http://www.southcoasttoday.com/article/20131007/NEWS/131009917.
41 Alex Kuffner, *New owners to shutter outmoded Brayton Point Power Station in 2017*, Providence Journal (Oct. 8, 2013).

J. Rejection of FirstEnergy's Proposed PPA Will Not Adversely Affect Either the Diversity or Reliability of Ohio's Fuel Mix

FirstEnergy claims that its proposed PPA would promote resource diversity[42] when it actually would merely subsidize the continued operation of uneconomic generating units and expose customers to significant risks.

Ohio's electric supply has not been very diverse, being heavily dependent on coal. Nor will it become more diverse with the proposed PPA. In fact, as shown in Figure 18, below, even if all of the output from the PPA coal units and Davis-Besse were replaced with lower-cost generation from natural gas-fired plants, 58 percent of the electricity produced in Ohio would still come from coal-fired units. If diversity is the goal, greater investments must be made on wind, solar and energy efficiency, resources that have no fuel costs and that produce jobs in Ohio.

Figure. 18: Ohio's 2014 Resource Mix Without the PPA Coal Units and Davis-Besse



Moreover, it isn't clear that any of the PPA coal units or Davis-Besse actually would be retired if the proposed Rider RRS bailout were rejected. At the same time, even if Rider RRS is approved,

42 Direct Testimony of Donald Moul, Public Utilities Commission of Ohio Case No. 14-1297-EL-SSO, August 4, 2014, at page 7, line 5.

the generation at the Sammis plant, at least, (and probably all of the PPA coal units) likely would continue to decline significantly as it is displaced by less-expensive generation from lower-cost natural gas-fired plants in Ohio and elsewhere in PJM.

In fact, PJM, not Ohio, is the proper frame of reference for assessing resource diversity and there is no evidence that the continued operation of the PPA coal units and Davis-Besse would make PJM fuel mix more diverse.

Part 2: Proposed PPA is Part of FirstEnergy's Ongoing Strategy to Improve its Weak Financials Without Addressing its Fundamental Over-Reliance on Coal

In 2014, IEEFA published a report detailing FirstEnergy's poor financial condition. The report cited FirstEnergy's declining stock price, declining net income, declining dividends and rising debt.

IEEFA traced FirstEnergy's poor financial condition to its decision to purchase Allegheny Energy in 2011—a decision that greatly increased its ownership of coal-fired power plants at exactly the time when the competitive electricity markets were becoming increasingly challenging for coal.

IEEFA's report concluded that "FirstEnergy's poor financial performance stems from the underlying condition that the company's business—the sale of electricity—is performing poorly and not generating sufficient revenue to cover expenses."

That report focused on the role of FirstEnergy's merchant coal fleet—unregulated coal plants that earn money by competing to sell power on PJM's regional wholesale electricity market. At a time of low wholesale market prices (driven by natural gas prices, increasing amounts of renewable power, and stagnating electricity demand), FirstEnergy's merchant coal plants have struggled to compete. At the time of our report, analysts at UBS Investment Research valued FirstEnergy's entire merchant generation business at $0.

Over the past year, FirstEnergy has taken no major steps to alter the composition of its fleet of power plants or to reduce its over-reliance on coal. As of the second quarter of 2015, 55% of FirstEnergy's power plant capacity was coal.[43] This is down only slightly from 58% as of the end of 2013.

The following chart shows the coal-fired power plants owned by FirstEnergy in 2014. Although three of these coal plants have retired in 2015, these were older, smaller plants that contributed less than 4% of FirstEnergy's merchant coal-fired generation in 2014.

[43] FirstEnergy FactBook, July 30, 2015.

Table 2. FirstEnergy's regulated and unregulated coal plants

Plant	Capacity (MW)	Regulated MW	Unregulated MW	Generation (GWh) in 2014	Current Status
Bruce Mansfield	2490		2490	17,143	Operating
W.H. Sammis	2220		2220	11,920	Operating
Harrison	1983	1984	0	12,846	Operating
Pleasants	1300		1300	8,578	Operating
Eastlake	1233		1233	1,184	Retired in 2015
Fort Martin	1107	1107		6,814	Operating
Lake Shore	245		245	184	Retired in 2015
Ashtabula	244		244	188	Retired in 2015
Bay Shore	136		136	940	Operating
Clifty Creek (FirstEnergy's share)	100	6	94	506	Operating
Kyger Creek (FirstEnergy's share)	83	5	78	459	Operating

Meanwhile, the U.S. coal market has continued its precipitous decline. The share of the nation's electricity generated from coal has fallen from 48% in 2008 to 39% in 2014 and was 34% in the first 10 months of 2015.[44] Analysts at UBS Investment Research predict that coal will account for only 18% of the nation's electricity generation by 2030.[45]

This is not a cyclical downturn for coal; the decline is structural. U.S. coal companies lost nearly three-quarters of their value in a little over a year, from August 2014 to October 2015.[46] FirstEnergy is wedded to an outdated generation technology that is not coming back.

FirstEnergy Has Embarked on Several Initiatives to Improve its Financial Position

On the company's third-quarter 2015 earnings call, FirstEnergy CEO Chuck Jones pointed to three factors that have improved the company's bottom line or that he said he expected would improve the company's near-term financial performance. The first is a major program of cutting costs, primarily at its competitive business. Analysts at UBS Investment Research attribute FirstEnergy's stronger financial performance in the first half of 2015 primarily to these cost-cutting measures.[47]

The second factor is the change to PJM's capacity market rules that have driven up prices for capacity. These rule changes were supported by FirstEnergy and other large owners of power plants in PJM. FirstEnergy power plants that had previously not been competitive cleared the auction at the new, higher prices and will begin receiving capacity payments.[48]

44 Energy Information Administration, "Net Generation by Energy Source: Total (All Sectors), 2005-October 2015", Electric Power Monthly, December 24, 2015.
45 UBS Securities, LLC, "U.S. Electric Utilities & IPPs: Pondering the Future Fuel Mix [Revised]", September 14, 2015.
46 Christopher Coats, "US coal producer market value only a fraction of its former self," SNL Financial, October 21, 2015.
47 UBS Securities LLC, "FirstEnergy Corp.: Keeping up with the Jones", August 3, 2015.
48 UBS Securities LLC, "FirstEnergy Corp.: Will Ohio come through?" October 13, 2015.

Third, FirstEnergy has proposed its PPA and Rider RRS Proposal in Ohio as a way to help shore up its financial position by ensuring that it receives the types of financial guarantees (such as full cost recovery and a guaranteed rate of return) for its generating assets that are typically found in a regulated system.

In October 2015, analysts with UBS Investment Research upgraded FirstEnergy from "sell" to "neutral," citing recent cost cuts, higher PJM capacity market prices, and the potential that Ohio regulators will approve some form of a PPA. UBS also noted that recent cost cuts and increases to capacity prices were leading it to put a positive valuation on FirstEnergy's merchant generation business, which it had previously valued at $0.[49]

FirstEnergy's PPA strategy continues its larger strategy to have captive ratepayers bail out the company for its coal-based business model. FirstEnergy signaled its new focus on regulation by appointing Charles Jones, the former president of FirstEnergy's regulated utility subsidiaries, to replace Anthony Alexander as CEO in 2015. On the company's fourth quarter 2014 earnings call, Mr. Jones stated, "We trust the regulator to look out for a future Ohio more than we do the markets." This statement emphasizes a major shift for FirstEnergy, which had previously and vociferously championed deregulation since it was first enacted in Ohio in 2000. Now that deregulation is no longer profitable for FirstEnergy, the company's strategy in Ohio has changed to attempting to have customers guarantee shareholder profits while taking on virtually all of the financial risks of the company's generation resources.

The PPA and Rider RRS would put nearly a third of FE's remaining merchant coal plants, as well as its struggling Davis-Besse nuclear plant, into an environment in which consumers will pay for plants that would, in the competitive market, have not been profitable in the past and are unlikely to be profitable in the future. This move, if approved by Ohio regulators, would thereby significantly reduce FirstEnergy's exposure to market price risks.

FirstEnergy's re-regulation strategy has included transferring 1600 MW of the coal-fired Harrison power plant from a deregulated subsidiary to a regulated West Virginia subsidiary in 2013. FirstEnergy has also reversed its strategy of aggressively expanding its retail customer base in deregulated markets and is now shedding retail customers. (FirstEnergy had previously aimed to capture retail market share from its competition by underselling competitors but reversed this strategy after the 2014 polar vortex, during which it was forced to buy wholesale electricity at record high prices from PJM and sell it at a loss to retail customers under fixed-price contracts). FirstEnergy's new strategy is not to sell any more electricity than is produced at its power plants, a goal it achieved in 2015.[50]

FirstEnergy's capital expenditures for 2015 also reflect a new emphasis on regulated operations. FirstEnergy budgeted only 20% of its capital expenditures for its deregulated generation business.[51] By contrast, in 2013 FirstEnergy spent 31% of its capital expenditure budget on its deregulated generation business.[52]

FirstEnergy's PPA is strategy suffers from at least two fundamental flaws. First, it abuses the regulatory process by shifting responsibility to Ohio ratepayers to bail out FirstEnergy for its past business decisions, including its push for deregulation and its merger with Allegheny Energy, which have resulted in FirstEnergy's weak financial position. This is not an appropriate use of the

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49 UBS Securities LLC, "US Electric Utilities & IPPs: Embedding the Auction Uplift," September 18, 2015.

50 FirstEnergy presentation at 50th EEI Financial Conference, Hollywood, Florida, November 8-11, 2015.

51 FirstEnergy 2014 10-K, February 17, 2015, page 13.

52 FirstEnergy 2013 10-K, February 27, 2014, page 14.

regulatory process. The concept of a fair rate of return assumes the ability of a utility to earn a return in the first place. The regulatory process is intended to smooth out the ups and downs of market cycles. It is not intended to replace them, as upheld by the Supreme Court in Market Street R. Co. v. Railroad Commission 324 U.S. 548 (1945):

> "Without analyzing rate cases in detail, it may be safely generalized that the due process clause never has been held by this Court to require a commission to fix rates on the present reproduction value of something no one would presently want to reproduce, or on the historical valuation of a property whose history and current financial statements showed the value no longer to exist, or on an investment after it has vanished, even if once prudently made, or to maintain the credit of a concern whose securities already are impaired. The due process clause has been applied to prevent governmental destruction of existing economic values. It has not and cannot be applied to insure values, or to restore values that have been lost by the operation of economic forces."[53]

Second, the PPA is a stopgap measures that do not address the fundamental problems facing FirstEnergy. As discussed in IEEFA's October 2014 report, FirstEnergy employed a series of short-term fixes (including asset sales and short-term borrowings) to improve its balance sheet from 2011 to 2014. While the PPA is a longer-term commitment, it too fails to fundamentally address the core problem faced by FirstEnergy—its continuing over-reliance on obsolete and uneconomic generation. Instead the PPA is evidence that FirstEnergy's only working business strategy is to continue to rely on short-term measures and ratepayer bailouts to prop up its financial position. When the PPA expires after eight years, it is unlikely that these plants will still be struggling financially and FirstEnergy will again seek to find a way to protect its shareholders from the risks of owning uneconomic generation by shifting all of that risk to customers.

FirstEnergy continues to struggle with high levels of debt and a heavily coal-dependent merchant generation business. Although the company has shown some recent signs of financial improvement, these are by no means the turnaround that company executives have been hoping for.

FirstEnergy's decision to double down on coal at the time of the Allegheny merger was certainly the wrong one. For the past several years, FirstEnergy has suffered financially as coal-fired generation has struggled to compete on the wholesale electricity markets. FirstEnergy has no real strategy to change its fundamental over-reliance on coal. By shifting gears to focus on regulated operations, including attempting to reap the financial guarantees provided in a regulated system through the Ohio PPA, FirstEnergy is effectively asking ratepayers to pay for its outdated business model and the Public Utilities Commission to walk away from its fundamental regulation responsibility.

53 See: Market Street R. Co. v. Railroad Commission 324 U.S. 548 (1945), in which the U.S. Supreme Court held that regulation is not intended to artificially prop up the profitability of a company which otherwise would not be profitable.

Part 3: The Benefits and Risks of an Orderly Transition Away From Uneconomic Generating Units, and the Need for an Economic Transition Plan

One of the arguments that FirstEnergy has raised in favor of its proposal is that, if the bailout is not granted, the company may decide to close the uneconomic power plants rather than continuing to lose money on them. Retiring Davis-Besse and/or Sammis would have two types of local economic impacts: the loss of jobs for workers at the plants and the loss of tax revenues of the communities where the plants are located.

While the closure of these plants would have significant economic impacts on the communities where they are located, the proposed bailout would only delay the inevitable. It is highly unlikely that the plants will be more profitable after the proposed PPA expires in eight years, meaning that ratepayers will have spent $4 billion to temporarily prop up financially struggling power plants while failing to address the underlying problem: uneconomic power plants that are unlikely to be competitive in a world of low natural gas prices, rapidly declining prices for renewable energy, and flat energy demand.

Ohio regulators should reject such a proposal and, instead, encourage the development of new energy resources that will create jobs and economic development in the state, while helping the Sammis and Davis Besse workers communities prepare for the inevitable transition.

FirstEnergy is a large corporation, with 15,500 employees across its operations.[54] Over the past six years, years, it has closed five coal-fired power plants in Ohio, including R.E. Burger, Eastlake, Lake Shore, Ashtabula, and several units of Bay Shore. According to published reports, FirstEnergy offered the majority of these employees who did not retire transfers to other jobs at the company.[55]

According to FirstEnergy, the Davis-Besse plant employs 700 people and Sammis employs 400 plus 140 full-time equivalent contractors. It is not clear how many of those employees would be offered other jobs at FirstEnergy if these plants eventually closed, although presumably some number of transfers would be available given the company's large size and the fact that other areas of the company are growing. (FirstEnergy sees its regulated transmission business as a major source of future growth and this will likely be an area of the utility that can continue to absorb displaced power plant employees.)

Davis-Besse and Sammis also contribute to the local tax base in Ottawa and Jefferson counties, respectively. According to FirstEnergy, Sammis paid approximately $5.5 million in local property

54 FirstEnergy Corporation, "About Us", https://www.firstenergycorp.com/content/fecorp/about.html.

55 John Funk, "FirstEnergy closes 104-year-old coal power plant, electric rates to rise," The Plain Dealer, April 15, 2015; WTOL 11, "Units at Oregon's Bay Shore Power Plant to shut down," January 26, 2012; John Funk, "FirstEnergy abandons plan to burn wood, will close boilers at R.E. Burger plant," November 17, 2010.

taxes in 2014 and Davis-Besse paid $6.3 million. A refueling project at Davis-Besse is expected to generate an additional $2.4 million a year in local property taxes. Retiring either plant would pose a challenge for the budgets of both communities.[56] In the past, FirstEnergy has worked with some communities to phase out tax payments over time to smooth the impact on community budgets.[57]

The people who work at Sammis and Davis Besse and the communities where those plants are located depend on these jobs and tax revenues. But these benefits would not disappear overnight if the bailout were rejected, as there is no evidence that FirstEnergy would or even could immediately shut down either plant. Instead, uneconomic generation would likely be phased out over a few years during which time an orderly and equitable transition can be planned for and implemented.

Some local initiatives have shown how communities can mobilize and build an early warning resource base to manage plant closures. In Tonawanda, N.Y., the impending retirement of NRG's Huntley coal plant will remove millions of dollars from the local tax base. Though the retirement of the plant was announced in August 2015, local community and labor organizations had seen the writing on the wall, recognizing the unprofitability of the plant,[58] and had begun planning for the plant's closure as far back as 2013. Among the initiatives:

- A community-labor alliance to create public support for continued funding for schools and other public services.
- A campaign to galvanize public support for re-employment of workers at the plant;
- Economic development discussions that focused on the affected site and for the economy as a whole.
- Broad dialogues with elected local and state leaders, public power authorities and corporate leaders.

Similarly, in Chicago, the retirement of the Crawford and Fisk coal plants on Chicago's lower west side in 2012 resulted in a constructive community process. Chicago's mayor established a task force that included utilities, community organizations and local elected officials and that developed recommendations for long-term economic development on the Crawford and Fisk sites. A proposal has been developed specifically to convert the Fisk site into a city bus garage, but this project has not yet moved forward.[59] The common theme of both the Chicago and Tonawanda initiatives are a stakeholder process that has brought the community together to envision new opportunities to take the place of the retiring coal plant.

Action can be taken at the state level to assist communities with economic transition when plants close. The mobilization in Tonawanda and other New York communities facing likely coal

56 EEFA has developed the outline of transition for two communities in New York State – Tonawanda and Tompkins County, both communities affected by plant closures. Each study identifies key local economic and fiscal trends in the area and briefly assesses the fiscal and employment outlook. The purpose of these short outlines is to spur community, business, labor and governmental stakeholders to develop realistic plans. See: Cathy Kunkel, David Schlissel and Tom Sanzillo, "Huntley Generating Station: Coal plant's weak financial outlook calls for corporate and community leadership," IEEFA, January 2014. See also: David Schlissel, Cathy Kunkel and Tom Sanzillo, "A Losing Proposition: Why the proposal to repower the Cayuga Plant should be rejected," IEEFA, August 2015.

57 Michael Schuler, "Impact on Burger plant closing eyed," Times Leader, January 9, 2011.

58 Cathy Kunkel, David Schlissel and Tom Sanzillo, "Huntley Generating Station: Coal plant's weak financial outlook calls for corporate and community leadership," IEEFA, January 2014.

59 Julie Wernau, "CTA bus garage could be part of Fisk power plant redevelopment," Chicago Tribune, January 19, 2015.

plant closings spurred the Legislature to pass a bill in 2014 backed with financial resources. One provision of the bill provides up to $19 million in state funds to municipal corporations and/or school districts where a fossil fuel electric generating facility has closed and caused significant revenue losses for the school district or municipality. Expenditures to local governments can be paid out over a five-year period. The funding is to come from contributions by the New York State Energy Research and Development Authority and the New York Power Authority.

The federal government also recognizes the need for greater support for communities facing plant closures. The POWER+ Plan, announced in 2015, is the first step toward a federal transition program to help communities. In October 2015, the White House announced $14.5 million in grants through the POWER Initiative, a precursor to the POWER+ Plan, of which $2.5 million went to initiatives in Ohio.[60] This includes a grant to 10 Ohio counties, including Jefferson County (home to the Sammis plant), for training and support to workers affected by coal plant and coal mine closures.[61] For Fiscal Year 2016, the federal budget includes $84 million for the POWER+ Plan's economic development and workforce retraining goals.[62]

Although these state and federal programs are a start, the amount of funding available is very small relative to the funding shortfall facing communities with retiring power plants. Plants like Sammis and Davis-Besse each contribute millions of dollars of property taxes each year to local governments, often providing a major source of funds for school districts.

What the planning for transition suggests thus far is that as plant closures become likely, fiscal and employment planning must start now. Budget actions need to be planned out over several years to smooth out impacts on local revenues and budgets.

Early warning on employment losses allows companies to think through their strategies about employee retention and for community supports to be put in place to assist with finding new employment and stabilizing the incomes of families affected. While the State of Ohio does not have any transition programs that are specific to fossil fuel plant closings, the Ohio Development Services Agency, the Department of Jobs and Family Services, and JobsOhio have a number of general job training and assistance programs that should be called upon to assist the affected communities, including the federally funded Rapid Response program to assist with mass layoffs or closures.

As proposed by FirstEnergy, the alternative to having the company either lose money from its uneconomic plants or retire them is for electric ratepayers—residents and businesses—to provide a subsidy estimated at $4 billion over the next eight years. This subsidy amounts to far more than the plants are worth and is far more than the revenues currently received from the plants by the communities where they are located. And of course FirstEnergy shareholders—dominated by very large financial institutions—would reap a 10.38% profit on this money.

The proposed bailout provides, at best, an expensive stopgap measure to shift to customers the financial risks posed by these uneconomic power plants. After the eight years of the proposed

60 White House Office of the Press Secretary, "Fact Sheet: Administration Announces New Workforce and Economic Revitalization Resource for Communities through POWER Initiative," October 15, 2015.

61 Ohio Means Jobs: Jefferson County and Harrison County, "Coal Grant," http://www.ohiomeansjobsjeffersoncounty.com/home/coal-grant

62 Though it no longer exists, the Clean Air Employment Transition Assistance program provides another example of federally funded transition efforts. This program was initiated as part of the 1990 Clean Air Act amendments to assist workers impacted by plants that closed as a result of tightening air pollution standards. http://law.justia.com/codes/us/1994/title29/chap17/subchapiii_3/partb/sec1662e

PPA, the plants will be even older and likely more expensive to operate, and it is unlikely that they will be profitable in a market that will have seen even more new entry from natural gas, renewables and energy efficiency. Ohio will once again face the challenge of how to transition if the plants close. In the meantime, the $4 billion ratepayer subsidy for the plants will have unnecessarily burdened residents and businesses and crowded out other investments that would have contributed more to Ohio's economy.

Rather than threaten the two host communities that they will suffer massive losses absent the infusion of a major ratepayer subsidy, FirstEnergy and the state of Ohio should turn their attention to how to provide appropriate support for workers and communities if and when the plants close. The state of Ohio should use this case as an opportunity to put a plan in place to help transition workers and communities that are impacted by the potential closure of obsolete power plants. The sooner the state and communities recognize the nature of the changes taking place, the sooner alternative budget and economic actions can be taken to create the upward cycle of change implied in the transition process.

Conclusion

The Public Utilities Commission of Ohio should reject the proposed settlement of FirstEnergy's plan for a Retail Rate Stability Rider (Rider RRS) through which the costs and risks of three of FirstEnergy's currently deregulated coal-fired plants (Sammis, Clifty Creek, and Kyger Creek) and its deregulated Davis-Besse nuclear plant would be passed on to captive customers of the utilities. The four plants whose costs would be passed through Rider RRS are currently unprofitable and will remain so for years to come, while market prices for power will continue to be low. This will result in at least $4 billion in costs to FirstEnergy's customers if the settlement is approved. The State of Ohio should recognize that markets are changing, and support the development of cleaner, modern and more efficient resources, as well as an economic transition plan for the workers and communities affected by closures of the aging plants.

Institute for Energy Economics and Financial Analysis

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