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Pleasants Coal Plant Purchase Would Be High Risk, Low Reward

Investors Face Same Scenario at PJM's Other Aging Coal-fired Power Plants

Executive Summary

On the Ohio River just a few miles from Parkersburg, W.Va., sits the Pleasants coal-fired generation station, an unregulated 42-year-old, 1,288-megawatt (MW) power plant in the competitive PJM electricity market. For years, its owners have threatened to sell or close the economically struggling plant, and have now set June 2023 as its retirement date. But they have left the door open to selling the facility, a contentious possibility that is likely to be repeated over and over across the region as current owners look to dispose of their aging, increasingly uncompetitive coal-fired generation facilities.

The Pleasants plant has a particularly checkered history of efforts to make it financially viable: an attempted sale between subsidiaries of Ohio-based FirstEnergy that would have returned it to regulated status and shifted its high costs to West Virginia ratepayers (rejected by regulators); a West Virginia tax relief bill targeting the plant that saved it $12 million annually; and a spinoff of owner FirstEnergy Solutions (FES, a FirstEnergy subsidiary) that went through bankruptcy and was later renamed Energy Harbor.

None of those efforts appear to have stemmed the plant's financial problems, however. In March, Energy Harbor announced plans to close Pleasants, along with its three-unit, 1,490 MW, coal-fired W.H. Sammis plant in Ohio, its other aging and similarly financially challenged facility 100 miles upriver, and become a "100% carbon-free" energy company focused on its three nuclear plants.

With coal power facing mounting economic challenges, the owners of PJM's coal plants have latched onto three options they say could serve as viable business models:

- Retrofitting facilities to enable blue hydrogen production,
- Linking with or selling to a crypto mining company, and

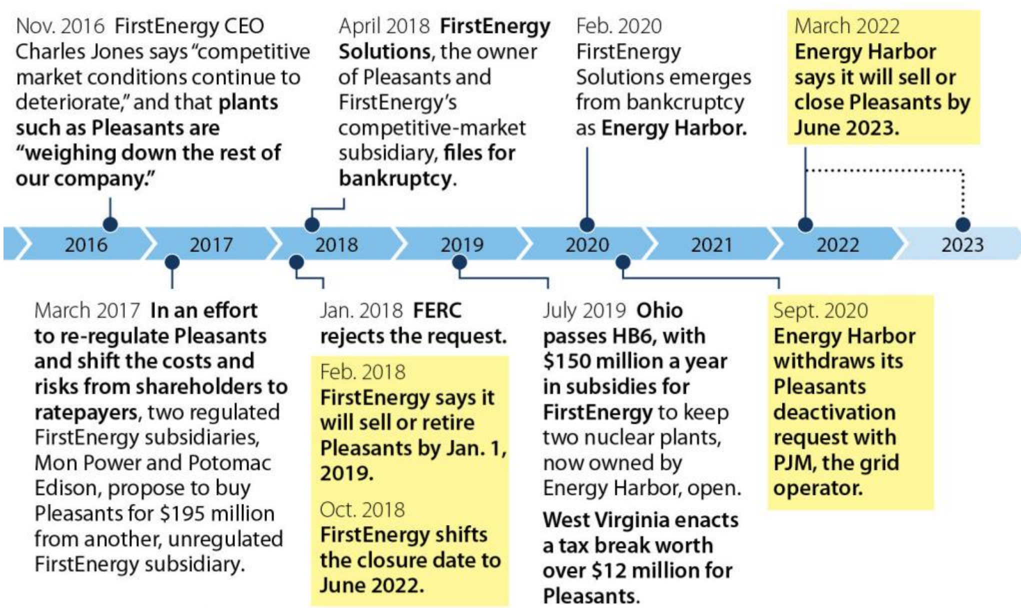
- Being bought by a coal company.

Notably, none of these options features the traditional use of power plants—generating low-cost electricity for sale in power markets—that usually attracts investors. IEEFA believes each of these non-traditional options holds significant financial risks for potential investors and would impair realistic efforts to plan for the inevitable plant closures in the future. Instead, a better option (particularly in light of the significant amounts of transition funding in the recently passed climate legislation) would be for plant owners and localities to begin working together now to devise plans to move away from coal.

In this report, IEEFA takes an in-depth look at the narrowing options facing coal plants in PJM.

Figure 1: Pleasants Coal Plant Timeline

The Pleasants coal-fired power plant has repeatedly been listed for closure by its owner, Energy Harbor (formerly FirstEnergy Solutions). The company now says it will be closed in 2023 unless a buyer is found. The two 644 MW units at the plant came online in 1979 and 1980.



Source: IEEFA research IEEFA

Introduction

Until 2020, the Pleasants plant was a deregulated, competitive power plant owned by FirstEnergy, a sprawling utility holding company with 10 regulated distribution companies in five states in the Mid-Atlantic that provides power to 6 million customers. Despite its size, FirstEnergy no longer participates in the competitive power generation arena, a notable transition from the company's early, vociferous support for deregulated electricity markets.

The company began moving away from competition in the early 2010s as low-cost gas undercut its coal and nuclear power units in the PJM market. In 2016, it announced plans to exit the competitive generation market; it completed its transition in 2020 when its former generation unit, FirstEnergy Solutions, emerged from bankruptcy as the newly independent, newly named Energy Harbor. Along the way, FirstEnergy convinced West Virginia regulators to approve a plan to put the 1,984MW Harrison coal plant back into the rate base of its regulated Monongahela Power Co. subsidiary. It tried the same tactic with the Pleasants coal plant, but to no avail.

Stuck with a plant it no longer wanted, FirstEnergy announced plans in early 2018 to close Pleasants. A West Virginia state tax rescue package bought the plant three years. However, FirstEnergy still wanted nothing to do with the coal plant and bundled it into the Energy Harbor spin-off, which also included three nuclear-power plants and another coal-fired plant, W.H. Sammis, all of which were facing financial challenges. Executives at Energy Harbor, which is now majority owned by the private equity firm Avenue Capital and Nuveen Asset Management, the investment arm of TIAA, said in March that they were going carbon-free, and would close or sell Pleasants by June 2023.

Options for Continued Operation

One of the individuals pushing hard for Energy Harbor to sell, rather than close, the plant is Jay Powell, president of the Pleasants County Commission; the coal plant is located in Pleasants County, W.Va. In interviews with several West Virginia media outlets following the company's closure announcement earlier this year, he said the county had received a number of inquiries about the plant. The inquiries, he said,[1] have centered on three principal options:

- Blue hydrogen production;
- Crypto mining operations;
- A coal company buyout to secure a market for its output.

[1] Energy News Network. One West Virginia community ponders life after a coal-fired power plant. April 13, 2022.

I. The Blue Hydrogen Mantra

The fossil fuel industry has latched onto the hope that so-called blue hydrogen—hydrogen made from methane, paired with carbon capture—can provide a transitional road to a lower-carbon future that still includes significant quantities of oil, gas and coal consumption.

Figure 2: Hydrogen Colors

GREEN HYDROGEN	BLUE HYDROGEN	GREY HYDROGEN
Made by using electricity from renewable energy technologies to electrolyze water (H_2O), separating the hydrogen atoms within it from the oxygen. No CO_2 by-product.	Produced using natural gas but with a percentage of carbon emissions that can be captured and stored, or reused. Negligible amounts in production due to a lack of successful CCS. Projects may end up stranded. Greenhouse gas emissions from upstream methane and uncaptured CO_2	The most common form (>95%) of hydrogen production today. Produced from natural gas via SMR and without any emissions capture. High carbon footprint; global annual emissions of 900mt CO_2 are equivalent to the combined emissions of the UK and Indonesia.

Trying to produce blue hydrogen using a coal plant would require the installation of carbon capture and storage (CCS) equipment on the power plant. This is a process that IEEFA has shown requires expensive new construction, is unlikely to meet the required capture targets, and results in very expensive and uncompetitive electricity. The hoped-for blue hydrogen would be a non-commercially viable product that couldn't be sold as clean and would cost much more than so-called gray or dirty hydrogen, which is produced without any carbon controls.

Questions About Carbon-Capture Performance—and the Problem of Coal Methane Emissions

Two carbon capture projects have been installed on coal-fired power plants.

One, now closed, was built at the W.A. Parish coal plant, southwest of Houston. The unit was designed to capture and treat a percentage of the flue gas from Unit 8, a 610-megawatt (MW) facility brought online in 1982. The project, dubbed Petra Nova, was effectively sized as a 240MW CCS unit. It came online at the end of 2016 and operated through May 2020. The operator, NRG Energy, officially closed the capture unit in the summer of 2020, blaming low oil prices for the decision. The company had developed the project with the expectation it could use the captured carbon dioxide (CO_2) for enhanced oil recovery (EOR) operations to recover its investment. Oil prices have risen sharply since, but the company has expressed no interest in restarting the project, and now would be unable to do so since Unit 8 is offline at least through the end of the year, due to a fire in May.

It is clear that the project did not hit its projected 90 percent capture rate during its three years of operation.[2] In fact, based on the data in a March 2020 report that one of Petra Nova's co-owners wrote for the U.S. Department of Energy, Petra Nova's capture rate was only 70 percent, even excluding the CO_2 emitted by the dedicated combustion turbine that provided the power to run the carbon capture facility.[3]

The second coal-based CCS unit is the still-operating project run by SaskPower in Canada. The Boundary Dam Unit 3, a 115MW boiler, has been in operation since the end of 2014. Its performance has been even worse than Petra Nova. Equipment problems have been a particular problem in the past year, taking the capture system offline for most of six months. Its problems call into question proponents' claims that carbon capture facilities would be able to operate at high levels of performance (90% or greater) continuously for years.

Energy Harbor's Empty Carbon-free Promise

Energy Harbor, the successor to FirstEnergy Solutions, the bankrupt competitive generation unit of FirstEnergy, announced its plan to go carbon-free in March. As part of the plan, Energy Harbor said it would retire or sell Pleasants and the remaining units at its W.H. Sammis coal-fired plant.

The transition, said Energy Harbor CEO John Judge, will position the company "as one of the few 100% carbon free energy infrastructure and supply companies in the US."

Although this may technically be true, it neglects a key point: Unless Energy Harbor closes its Pleasants plant—instead of selling it—the company will effectively be responsible for a plant that has released an annual average of 7.4 million tons of carbon dioxide (CO2) into the atmosphere since 2010. That really doesn't add up to being carbon-free.

But beyond these carbon-capture performance problems lurks another, more insidious problem: The coal mines supplying these power plants produce significant amounts of methane, a greenhouse gas that is much more potent than the carbon dioxide produced during combustion.

The Pleasants power station buys more than two-thirds of its coal from two underground mines in West Virginia, located in Marshall and Ohio counties. Together the two mines produced 13.8 million tons of coal and released 105,453 metric tons of methane in 2020. Converted to carbon dioxide equivalents (CO_2e)

[2] IEEFA. 'Holy Grail' of carbon capture continues to elude coal industry; 'cautionary tale' applies to domestic and foreign projects alike. November 19, 2018.
[3] U.S. Department of Energy
Office of Scientific and Technical Information. W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project (Final Technical Report). March 31, 2020.

using the 100-year time scale utilized by the Environmental Protection Agency, that equals just under 2.7 million tons of CO_2e annually.

However, the 100-year method understates methane's short-term impact on global climate. IEEFA considers a shorter, 20-year period to be more realistic when evaluating methane. For comparison, the Intergovernmental Panel on Climate Change says methane's global warming potential at 100 years is 25 times that of CO_2; at 20 years it is 84 times that of CO_2, or more than three times more destructive. Using this approach results in eye-opening emissions numbers from some of the underground Appalachian coal mines.

On the 20-year scale, emissions from the Marshall and Ohio county mines jump to more than 8.8 million tons of CO_2e annually—more than the CO_2 emissions emitted annually on average by the Pleasants plant. In fact, if ranked as a power plant, the mines would effectively be the 29th largest emitter in the U.S.

Adding the methane emissions from the coal used at Pleasants, whether from the Marshall and Ohio mines or its other suppliers, would significantly worsen any measure of carbon-capture performance at Pleasants, effectively adding more than 10 percent to its annual emissions total.

This problem is even worse at other underground coal mines in the region, particularly the three-mine Consol facility known as the Pennsylvania Coal Complex. The facilities emitted 238,345 tons of methane in 2020—more than 20 million tons of CO_2 when converted to CO_2e over 20 years. The emissions would make it, in effect, the second-largest power plant emitter in the country. Power plants buying coal need to factor mine-methane emissions into their long-term environmental plans.

Questions About Cost

Cost concerns are another key question for coal-fired CCS. These projects essentially amount to bolting a chemical plant onto a power plant, and that is expensive. The Petra Nova plant, at 240MW, is small, but it still cost $1 billion to build. The smaller Boundary Dam facility cost C$1.5 billion, about USD$1.15 billion.

Scaling up is clearly going to raise the cost, even if companies are able to achieve some learning-by-doing savings. In New Mexico, the company looking to retrofit two units totaling 847MW at the San Juan Generation Station currently estimates that it will cost $1.4 billion to add CCS at the plant. However, since no construction has begun, any outside investor should evaluate the figure with a high degree of caution. In its initial proposal, the company said the retrofit would cost no more than $800 million.[4]

[4] Energy and Policy Institute. Acme Equities wants to add expensive carbon capture to distressed coal plant. March 3, 2009.

Similarly, backers of Project Tundra, a plan to add CCS at the 447MW Unit 2 of the Milton R. Young coal plant in North Dakota, now estimate the project will cost $1.45 billion, up from $1 billion initially.[5]

No public estimate has been done for the Pleasants facility, but retrofitting even one of the two units with CCS is almost certain to cost more than $1 billion. The price tag would boost electricity prices from the plant significantly, making it even harder for the facility to compete in the PJM market. The higher electricity costs would raise the price of the blue hydrogen as well, potentially pushing it out of the market as green hydrogen prices continue to decline.

Other options, such as retrofitting the plant and gasifying the coal, are also certain to raise costs significantly. Here, the Edwardsport gasification plant is a great example. That 618MW facility, built by Duke Energy in Indiana, came online in 2013. Its performance since has been spotty, with some of the highest prices in the Duke system—and it doesn't even capture any of the produced CO_2. The other relevant example, Southern Company's Kemper project in Mississippi, turned out even worse. The company spent $7.5 billion building the project, which included a gasification and CCS facility, but ultimately abandoned those parts of the project. The completed facility now runs entirely on natural gas with no carbon capture.

Questions About Market Size

Looking ahead, it is highly uncertain how much blue hydrogen will even be needed—or economic. Its proponents see opportunity for hydrogen virtually everywhere. IEEFA is far less certain this growth in demand will materialize, as we outlined earlier this year.[6] In addition, with gas prices now significantly higher than they have been for most of the last 10 years, green hydrogen, produced with renewable energy and electrolysis, is increasingly economic. Green hydrogen also has much better long-term development prospects, given the absence of any greenhouse gas (GHG) emissions.

The recently passed Inflation Reduction Act provides a significant scaled credit for what is called "qualified clean hydrogen." The law doesn't single out production methods, but the sliding scale is structured so that fossil fuel-based hydrogen is unlikely to qualify for the maximum credits even with carbon capture controls. The credit also requires full lifecycle emissions calculations, meaning upstream methane emissions would be factored into fossil-based hydrogen production.

The law's full impact is still somewhat uncertain, but early analyses expect green hydrogen to benefit significantly from the new credit. As one said, "This is likely to make green hydrogen projects immediately economically viable by significantly

[5] The Forum. With cost upped to $1.45B, Project Tundra seeks funds from North Dakota energy board. March 31, 2022.
[6] IEEFA. Blue Hydrogen: Technology Challenges, Weak Commercial Prospects and Not Green. February 8, 2022.

increasing the economic attractiveness of green hydrogen produced from renewable sources."[7]

It is also important to note that companies taking advantage of the clean hydrogen credit cannot also use the new higher carbon capture credit included in the legislation.

Questions About Age

Finally, all these questions revolve around plants that are, in a word, old. The two units at Pleasants are 43 and 42 years old, advancing middle age for a coal plant.

Research by the Energy Department's national labs and the Electric Power Research Institute (EPRI) has shown conclusively that plant performance, generally measured by the facility's heat rate, declines steadily over time. As a plant's heat rate increases, it must burn more fuel to produce the same output, effectively raising costs. Plant availability also decreases with age, which translates into lost sales, again leading to cost increases as fixed operations and maintenance costs are distributed across less production.

Finally, maintenance costs tend to increase as plants get older. Here, the problem is likely being exacerbated by the increase in cycling operations at plants generally designed to run in steady-state mode. The DOE/EPRI research shows that the increase in cycling is likely to have major negative impacts on coal plant equipment and performance.

Temperature changes in key plant operating systems resulting from

Private Equity's Aging Problem

The performance problems caused by age are likely to become particularly apparent in the 16 coal-fired power units owned by private equity (PE) firms.

These units have a total capacity of 12,502MW, but 84 percent of that—10,519MW—is already at least 40 years old.

More worrisome both for current owners and potential investors should a current PE firm want out, nine of the 16 units—totalling 6,438MW of capacity—are more than 50 years old. The odds of any of those units operating long enough to recover any CCS retrofit costs are long indeed.

Of the three units less than 40 years old, two—Brandon Shores Units 1 and 2—must stop using coal by 2025 under a settlement negotiated with the Sierra Club.

The sole unit less than 20 years old, the 710MW Longwood facility in West Virginia, is also an unlikely candidate for major capital investment. The facility, which came online in 2011, has operated well, posting an average capacity factor of 75.3% in the decade since it began commercial operations. However, the PE-owned facility has also declared bankruptcy twice in 12 years. Additional capital investments would just further undercut the plant's competitiveness in PJM.

[7] J D Supra. Inflation Reduction Act: Key Green and Blue Hydrogen and CCUS Provisions. August 15, 2022.

cycling have been identified as a particular concern: "Studies … have identified temperature transients and non-uniform temperatures as the major source of reduced component lifetimes and accelerated failure rates."[8] In addition, an Argonne National Laboratory study said, "repetitive cycling and resulting temperature changes create stress in components leading to creep and fatigue failures."[9]

In an earlier study, EPRI researchers raised many of the same concerns, noting:

- "Thermal fatigue of major components is the key driver of damage due to ramping and frequent starts.
- "Creep-fatigue interaction will become an increasingly important damage mechanism when aging units are forced to operate flexibly.
- "Flexible operations can create potential for short term overheating; not a long-term effect, but potentially affects availability because of associated increase in thermal fatigue damage."[10]

Data from Monitoring Analytics, the independent market monitor that tracks performance issues for PJM, show clearly that maintenance and aging issues are beginning to show up in the region's coal plants. Their equivalent availability factor (EAF), a key performance indicator that measures the number of hours that a plant is available to generate at full capacity, fell to a record low of 67.4% in the first six months of 2022. At the same time, maintenance outages climbed to a record high, with coal plants offline for repairs more than 11% of the time.[11]

Banks and investors being asked to loan money for a project that likely will cost more than $1 billion need to consider the age issue carefully. Sinking that kind of money into a plant and assuming it will operate effectively and at low cost for another 20 years would be an extremely risky proposition, at best.

And here, Pleasants is typical of the installed coal-fired capacity in PJM. According to the system's independent market monitor, there are 42,982.9 MW of operating coal-fired capacity in the region.[12] Of that, a whopping 82 percent is already 40 years old and almost half is 50 years old. That makes any long-term retrofit investments involving blue hydrogen a huge gamble.

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[8] Donald Hanson, Argonne National Laboratory, et al. "Optimization of a Prototype Electric Power System: Legacy Assets and New Investments." December 2018. p. 28.
[9] *Ibid.*
[10] U.S. Department of Energy Office of Scientific and Technical Information. Fossil fleet transition with fuel changes and large scale variable renewable integration. March 31, 2015, p. 106.
[11] Monitoring Analytics. Quarterly State of the Market Report for PJM, January Through June. 2022, Section 5, p. 352.
[12] *Op. cit.*, p. 315.

II. Crypto's Siren Song

The economics of crypto mining companies depend on two factors: A high price for cryptocurrencies and a lot of dependable, low-cost electricity to run their power-hungry mining computers. Buying and running a 40-plus-year-old coal-fired power plant is unlikely to meet either the dependability or low-cost criteria.

The Pleasants plant would also likely produce much more electricity than even a large crypto company could use. According to a congressional investigation, six of the largest crypto companies in the U.S. reported that they use just over 1,000MW of electricity currently.[13] They all have plans to expand, but the takeaway is that even a large user would be buying surplus generation capacity by acquiring the 1,288MW Pleasants plant.

There also is some uncertainty about the long-term outlook for electricity demand growth from crypto mining. Ethereum, the sector's second-largest miner, just switched from the highly electricity-intensive proof-of-work verification process to the much more efficient proof-of-stake process.[14] If other companies follow suit, demand could be significantly reduced.

A third party could conceivably buy the facility, with the intent of having an anchor crypto tenant and then shopping the rest of the power into the PJM market, but that would bring the new owner face-to-face with the same problems that originally drove FirstEnergy away—generally weak power prices in the region, low capacity auction results and low growth demand forecasts.

Power prices in PJM have risen in the past year, but so have fuel costs for both coal- and gas-fired generators. As a result, coal has lost market share over the first six months of 2022. Specifically, data from the Energy Information Administration's hourly grid monitor shows that coal generation has dropped 6% year-to-date compared to 2021, even as total generation in the region has climbed by 1.5%. This continues a decade-long trend driven by the buildout of gas-fired capacity in PJM, particularly of efficient combined cycle gas turbines (CCGTs). Total CCGT capacity has almost doubled since 2013, climbing from 27,292MW to 54,048MW at the end of June.[15]

Going forward, the massive surge of wind and solar generation planned throughout the region also will pose a growing threat to the region's coal plants. While still a small percentage of the market, both resources have grown quickly. Wind generation is up 34% since 2019; solar has jumped 218%. Thousands of megawatts of new renewable generation capacity are currently in the regional generation queue.

At the same time, long-term demand growth forecasts remain low in PJM, meaning older, more expensive plants such as Pleasants will have a harder time selling into

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[13] Protocol. Democrats release 'disturbing' crypto mining investigation. July 15, 2022.
[14] Ethereum. Ethereum Energy Consumption. September 15, 2022.
[15] Monitoring Analytics, *op. cit.*, p. 667.

the market. This in turn becomes a cycle, as lower revenues from power sales result in higher per-unit costs, making it that much harder to sell the plant's electricity.

There also are questions about FES/Energy Harbor's maintenance spending at Pleasants in recent years. These questions, which are separate from the general aging concerns noted above, raise uncertainty about its ability to perform reliably into the future. FirstEnergy has been looking for an exit strategy from Pleasants for years. As part of that effort it undoubtedly has looked to minimize maintenance investments. FirstEnergy's Jones acknowledged as much back in 2016, telling analysts on an earnings call, "we have delayed investments where possible at our fossil fleet." Given the company's goal of getting out of the competitive generation market, it is unlikely it changed that mantra in the intervening years, meaning maintenance investments have probably been kept as low as possible. The decreased investment potentially forces any new owner into an expensive game of catch-up.

The situation at the San Juan Generating Station in New Mexico is illustrative of what could happen at Pleasants or other PJM plants where maintenance has been delayed. PNM, the majority owner and operator of the coal-fired San Juan facility, has been planning to close the remaining two units, which have a combined generating capacity of 847MW, for years. Both had been slated for closure June 30, but delays in completing replacement power projects prompted the utility to keep Unit 4 online through the summer.

Another company, Enchant Energy, is looking to take over San Juan, keep it running and eventually add carbon capture equipment to the plant. IEEFA has been highly critical of Enchant's CCS proposal,[16] but for this report the key factor is how much money Enchant says it will need to spend to complete delayed maintenance to keep the plant running. In a 2021 presentation,[17] the company said it had identified $139 million in deferred maintenance costs; the figure has almost certainly increased in the intervening year.

It is uncertain how much maintenance has been deferred at Pleasants, but by corporate admission it is not zero. And anything above zero is only going to further compromise the plant's competitiveness.

[16] IEEFA. Enchant's proposed CCS project at the San Juan Generating Station: False promises and major risks. February 1, 2020. Also see: IEEFA. Where's the Beef? Enchant's San Juan Generating Station CCS Retrofit Remains Behind Schedule, Financially Unviable. May 2021.
[17] Enchant Energy. City of Farmington & Enchant Energy Corporation: The Future of San Juan Generating Station. July 13, 2021.

III. A Coal Company Buyout

A third option often floated is for coal plants to be sold to a coal-mining company. In February, Hallador Energy announced plans to acquire the two-unit, 991MW Merom Generation Station from Hoosier Energy, a generation and transmission (G&T) cooperative that serves distribution co-ops in Indiana and Illinois. Hoosier had said previously that it would retire the coal-fired power plant in May 2023 because of cost concerns. In making the closure announcement, Hoosier estimated it would save members $700 million over 20 years.

For Hallador, the deal was clearly a move to guarantee demand for its coal: Merom has burned an average of 2.29 million tons of coal annually since 2015. As part of the deal, Hoosier agreed to buy all of the plant's electric output through May 2023, and then a reduced share of its capacity and energy through 2025.

The deal looks like a winner for Hoosier since it was able to offload its costly coal plant and get Hallador to assume "certain decommissioning costs and environmental responsibilities." In addition, while the figures are not publicly available, it is likely Hoosier's power purchase agreement with Hallador is for less than the $70+ per megawatt-hour the G&T has charged members for power in recent years, which benefits all the distribution co-ops to which Hoosier Energy sells power.

Whether the deal will work for Hallador remains to be seen. In its first quarter report in March this year, the company said it expected the deal to close in the third quarter and that it would significantly add to the company's profitability and increase earnings before income taxes, depreciation and amortization (EBITDA).[18] However, by the second quarter, the company's enthusiasm had waned: "The Merom Power Plant is not expected to meaningfully contribute to EBITDA in 2022 and 2023."[19]

There also is significant uncertainty as to whether a similar deal could even be negotiated in the PJM market given Pleasants' merchant plant status—there is no legacy utility looking to offload the plant for a potentially cheaper power purchase agreement (PPA). Indeed, that has been Pleasants' problem for years: it sells electricity into the PJM market and has had trouble competing, according to its owners.

For almost six years, First Energy and its associated subsidiaries and spinoffs have been complaining about the competitive landscape in PJM. In November 2016, for example, FirstEnergy CEO Charles Jones said that "competitive market conditions continue to deteriorate, punctuated by weak power prices, insufficient results from recent capacity auctions and anemic demand forecasts. The fact is competitive generation is weighing down the rest of our company."[20]

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[18] Hallador Energy Company. Form 10-Q. May 23, 2022, p. 8.
[19] Hallador Energy Company. Form 8-K. July 8, 2022, p. 3.
[20] FirstEnergy. Q3 2016 Results -Earnings Call Transcript. Nov. 4, 2016.

Clearly, if Pleasants couldn't make money then, it is unlikely to do so moving forward. The PJM capacity auction results for the six years bracketing Jones' comments averaged $117.69/MW-day, with only one year below $100. In contrast, the three auctions since have averaged just $88.84/MW-day, with the current year falling to just $50/MW-day and next year's capacity price dropping to $34.13/MW-day. In addition, since Jones' complaint, significant amounts of new CCGT capacity have been brought online, new renewables and storage are now the lowest-cost generation resource, and expectations for future demand growth remain low. In other words, the competitive landscape for aging coal-fired power plants remains difficult.

Conclusion

Transitions are hard, but there is no doubt the array of risks associated with trying to keep Pleasants operating far outweigh the potential benefits for any outside investors. The plant has struggled to compete in the PJM electric market for years, and lower capacity-market payments, higher coal prices, aging components, and deferred maintenance are going to make its struggles even more challenging in the future.

Planning for the inevitable closure of Pleasants and other aging power plants in PJM is the proper course of action.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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