# THE PJM CAPACITY MARKET: A TALE OF MISSING MONEY


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# Executive Summary

Electric grid failures in California (2020), Texas (2021), and the Mid-Atlantic (2022) have reignited a long-standing debate over resource adequacy. A key question that remains unanswered, however, is how much money is truly 'missing' from generators to induce sufficient investment in capacity. This paper explores the shifting nature of missing money in two ways. First, merchant generator cost of capital is estimated using a sample of public comparable firms. Second, generator performance—and by extension, financial health—is evaluated by comparing simulated wind and solar power production data with real performance assessment intervals during Winter Storm Elliott.

Key Findings:

- PJM's capacity market outcomes and cost of debt financing are both inputs to each other, creating a feedback that begins to imitate parts of original cost of service regulation.
- PJM's previous penalty for capacity resource underperformance, which was based upon a fixed quantity (1.5x Net CONE ICAP) instead of the actual clearing prices for relevant times, encouraged upward pressure on capacity bid prices. This has been remedied. But short-term bid inflation pressures remain.
- Cost of capital calculations based upon publicly comparable firms with broad power plant portfolios should be biased upward to account for increased riskiness of cash flows to peaker plants. However, current basis point adjustments for this premium lack precision—adjusting missing money estimates in a fashion that is frankly indefensible. I caution PJM against adopting NYISO's approach to a battery energy storage system (BESS) basis premium in this regard.
- Many parameters and rules of capacity markets, as well as capacity market resource bids themselves, are based upon a large collection of best guesses.

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# Background

Capacity market designs have varied over time and across geographies, but they all have the same core components: (1) a demand forecast; (2) an administratively assumed price elasticity of demand; and (3) a maximum price cap approximating the cost of new entry.[1] This last component is the focus of my paper.

## Capacity Price Ceilings: Estimating the Cost of New Entry

PJM estimates the costs to build and operate new power plants every four years.[2] This approximation is commonly referred to as the gross cost of new entry, or Gross CONE. After Gross CONE is estimated for a given delivery year, a series of adjustments is made to net out anticipated revenues to the project from PJM's energy and ancillary services markets. Accordingly, the 'missing money' for a new merchant power plant providing capacity is equal to *Gross CONE – Energy Market and Ancillary Services (E&AS) = Net CONE*. This Net CONE value is used as an upper $/MW-day limit for capacity auction revenues.

While Net CONE calculations include multiple parts, my analysis will focus on the theory-heavy—and frankly malleable—portion of this value for PJM, which is their assumed discount rate. The discount rate PJM applies to future cash flows is equal to an assumed after-tax weighted-average cost of capital (ATWACC) for a new capacity resource.

Selecting an appropriate CONE, and by extension, an appropriate discount rate via an ATWACC, will naturally vary across different project types. Historically, Net CONE values have been based on a natural gas combustion turbine (CT) in PJM. However, other markets such as NYISO are starting to consider a battery energy storage system (BESS) as an appropriate reference technology. Natural gas combined cycle (CC) plants have also been considered. But by and large, CTs have carried the day. Perhaps unsurprisingly, the Electric Power Supply Association (EPSA) has filed a complaint with the NYISO to stop the transition to BESS as a reference technology[3]—mirroring their infamous legal case in FERC v. EPSA (2016) where they argued against demand response being allowed to participate in wholesale electricity markets, and by extension, potentially outcompete their members' generation assets.[4] EPSA's arguments have failed for now. Though time will tell if they will

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[1] Todd S. Aagaard and Andrew N. Kleit, Electricity Capacity Markets, 2022. Cambridge University Press.
[2] Generic cost escalations are assumed to cover the intervening years between quadrennial reviews.
[3] Electric Power Supply Association. EPSA Files Comments on NYISO's Demand Curve Reset Filing. 2025. https://epsa.org/filings/epsa-files-comments-on-nyisos-demand-curve-reset-filing/
[4] U.S. Supreme Court. *FERC v. EPSA*. 2016. Retrieved from Justicia U.S. Supreme Court Center. https://supreme.justia.com/cases/federal/us/577/14-840/case.pdf

be resurrected and applied towards the next incarnation of novel energy and capacity resources.

FERC recently accepted the NYISO proposal for BESS as a reference technology in February, 2025,[5] including recommendations to add an extra risk-premium for battery storage technologies to their ATWACC assumptions.[6] Similar to NYISO's fact-finding and determination process, my analysis will also include a nod to the conceptual underpinnings of why this basis point adjustment may also be reasonable in PJM. Though to be clear, while a directional adjustment is warranted, RTO basis adjustments outside of observable term loan agreement or comparable debt facilities—not to mention geographic risk premiums from one load zone to the next—should be viewed as educated guesses that are far from perfect.[7]

# Estimating ATWACC for Merchant Power Plants

New power plants and energy storage facilities are financed through a combination of debt and equity. While precise deal terms are not publicly available, costs of debt and equity can be estimated using a combination of financial theory—such as the capital asset pricing model (CAPM)—as well as financial statement disclosures from public companies.

If private firm financials could be independently reviewed and verified by PJM without breaching trust or contract terms, this could simply be estimated directly. However, without this mechanism, ATWACC methodologies will continue to rely on comparable firms.

## Selection of Comparable Firms

PJM's latest quadrennial review of after-tax WACC assumptions were recommended by The Brattle Group and Sargent & Lundy in 2022 for the 2026/2027 capacity delivery year. Brattle's selection of comparable public firms for new PJM merchant power plant

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[5] FERC e-Library, Order Accepting Tariff Revisions re New York Independent System Operator, Inc. under ER25-596. 2025. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250128-3048&optimized=false

[6] Troutman Pepper Locke, FERC Accepts NYISO's Proposal Regarding their 2025-2029 Demand Curve Reset. By Quintessa Davis & Dixon Wallace, February 4, 2025. https://www.troutmanenergyreport.com/2025/02/ferc-accepts-nyisos-proposal-regarding-their-2025-2029-demand-curve-reset/

[7] Given the complexity of capacity markets, this series of educated but unobservable guesses can quickly spiral into mispriced capacity signals. For NYISO, this may matter little given their 1-month forward auctions, which helps keep their projections within a tighter expected range of values. But in PJM's 3-year forward auction, the confidence bands for educated guesses can compound and grow quite wide.

development includes AES, Vistra, and NRG Energy.[8] However, in the three years since Brattle's quadrennial review for PJM was published, Talen Energy has re-listed publicly on the NASDAQ and Constellation Energy IPO'd following its separation from Exelon.[9][10] In addition to these two new companies to consider, market premiums for the existing companies have also changed considerably.

Vistra and NRG Energy have risen in value rapidly. Meanwhile, AES Corporation's market capitalization has declined precipitously, falling from $19 billion in 2022 to $8.8 billion today.[11] Given these changes, and the inclusion of two new peer comparable firms, I hypothesize that WACC calculations have changed in appreciable ways. Accordingly, I calculated new weighted-average costs of capital for this expanded group of peer firms (Appendix A1). My decision to include Talen is discussed in Appendix A7.

## Estimating Cost of Equity via the CAPM

To quote two of the godfathers of modern financial theory, Eugene F. Fama and Kenneth R. French: "The version of the CAPM developed by Sharpe (1964) and Lintner (1965) has never been an empirical success."[12,13] Nevertheless, it is still widely used by analysts and practitioners alike. Capacity markets are no different. PJM, NYISO, MISO, CAISO, ERCOT, ISO-NE, and SPP all use the Sharpe and Lintner version of the CAPM to help formulate their

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[8] The Brattle Group. PJM CONE 2026/2027 Report. April 21, 2022. https://www.brattle.com/wp-content/uploads/2022/05/PJM-CONE-2026-27-Report.pdf

[9] Constellation becoming its own publicly traded entity will in some ways help consultants recommend a higher conceptual COE than would otherwise be possible. See Appendix A1 for how it compares to peer firms.

[10] Exelon Corporation. *Exelon Completes Separation of Constellation, Moving Forward as Nation's Premier Transmission and Distribution Utility Company*. February 2, 2025. https://www.exeloncorp.com/newsroom/exelon-completes-separation-of-constellation

[11] United States Securities and Exchange Commission. *The AES Corporation Fiscal Year 2024 Form 10-K*. published February 28, 2025. https://www.sec.gov/ix?doc=/Archives/edgar/data/0000874761/000087476125000013/aes-20241231.htm#fact-identifier-658; AES Corp Shares Outstanding of 711,900,547 x $12.41/share as of March 30, 2025.

[12] Eugene F. Fama and Kenneth R. French. *The Capital Asset Pricing Model: Theory and Evidence*. Journal of Economic Perspectives—Volume 18, Number 3—Summer 2004—Pages 25–46. Retrieved from Dartmouth Tuck School of Business. https://mba.tuck.dartmouth.edu/bespeneckbo/default/AFA611-Eckbo%20web%20site/AFA611-S6B-FamaFrench-CAPM-JEP04.pdf.

[13] Note: excess risk-adjusted returns in the CAPM, denoted by α (alpha) should always equal zero. Yet non-zero alphas persistently reveal themselves in strategies such as betting against beta—beta arbitrage where one takes a long position in assets with low betas and shorts assets with high betas—as well as the standard Carhart four-factor model which adds size, value, and momentum to the CAPM.

cost of equity (COE) assumptions for new power plants.[14,15,16] I chose to continue this flawed but best guess tradition, using the CAPM formula as follows:

$$r_i = r_f + \beta_i[\mathbb{E}(r_m) - r_f]$$

Where $r_i$ is the return of a given asset, $r_f$ represents the risk-free rate, The $\mathbb{E}$ operator is the Expected Value, $r_m$ represents the broader market return—commonly estimated from S&P 500 data—and where the beta (β) of each asset represents the degree to which its returns covary with the market:

$$\beta_i = \frac{Cov(r_i, r_m)}{\sigma_m^2} = \frac{\sigma_{i,m}}{\sigma_m^2}$$

Expectations about the equity-risk premium (ERP), denoted by $[\mathbb{E}(r_m) - r_f]$ in the CAPM formula, are the subject of rich debate. Ivo Welch and Amit Goyal, professors at Brown and Emory respectively, reviewed a variety of predictive factors in 2008, concluding that many standard models have poor predictive power over time.[17] I believe contemporary papers on ERP by NYU Stern professor Aswath Damodaran, whose figures are updated every year, should be selected as a potential benchmark for ERPs. However, for the purposes of this analysis, I elected to mirror the public ERP predictions of Duff & Phelps, which is a long-time industry standard used by Brattle and the Analysis Group in their ATWACC analyses. Duff & Phelps, now owned by Kroll, published their March 19, 2025 recommendation of a 5% target ERP.[18] Looking at historical press releases by the company, Kroll publicly recommended a 5.5% ERP at the same time Brattle cited Kroll's private cost-of-capital

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[14] The Brattle Group. PJM CONE 2026/2027 Report. April 21, 2022. https://www.brattle.com/wp-content/uploads/2022/05/PJM-CONE-2026-27-Report.pdf

[15] Analysis Group. *Analysis of the ATWACC of New Entry for the ISO New England Forward Capacity Market*. August 10, 2023. https://www.iso-ne.com/static-assets/documents/2023/08/a08a_mc_2023_08_08-10_fcm_netcone_updates_mopr_reforms_for_fca19_analysis_group_presentation.pdf

[16] Analysis Group, *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025-2026 through 2028-2029 Capability Years*. October 2, 2024. https://www.nyiso.com/documents/20142/47366127/Analysis-Group-2025-2029-DCR-Final-Report-Updated.pdf

[17] Amit Goyal and Ivo Welch. *A Comprehensive Look at The Empirical Performance of Equity Premium Prediction*. The Review of Financial Studies, Volume 21, Issue 4, July 2008, Pages 1455–1508. 17 March, 2007. https://doi.org/10.1093/rfs/hhm014

[18] Kroll. Kroll Cost of Capital Recommendations and Potential Upcoming Changes – March 2025 Update. March 19, 2025. https://media-cdn.kroll.com/jssmedia/kroll-images/pdfs/kroll-cost-of-capital-recommendations-and-potential-upcoming-changes-march-2025.pdf?_ga=2.61405676.1753882792.1745198419-1335826748.1745198419

navigator showing 7.46%.[19,20] Considering this nearly 200 basis point gap, not to mention the constant flux within current U.S. capital markets given recent tariff announcements, I included sensitivity analysis in Appendix A5 with my calculated ATWACC results across different ERP ranges.

Selecting an appropriate risk-free rate also has a tinge of art to it rather than being a firm science. To truly discount a new power plant's cash flows, every year of operations should have its own corresponding discount rate that considers time-varying treasury yields at different maturities. That said, given the one input variable for a risk-free rate in the CAPM, I elect to use a 1-year treasury yield instead. This treasury tenor offers a spot value for the risk-free rate of 3.86% as of April 4, 2025. For comparison, Kroll's long-term estimate of $r_f$ is currently 3.5%.[21]

Finally, there is one further wrinkle to the Cost of Equity (COE) derived from the CAPM for this analysis. Individual peaking plants of any configuration, fossil or BESS, have a fundamentally different risk profile—and therefore demand a different capital stack and risk-adjusted return expectation—than a company's broader fleet of natural gas combined cycle, dual fuel, nuclear, or legacy coal plants. Accordingly, the results of my analysis of comparable firms are biased upward to account for this higher unobservable but nevertheless tangible underlying premium.

## Estimating Cost of Debt

Unlike cost of equity, cost of debt (COD) can be observed directly. Two common approaches to estimating company COD are credit spreads and company-specific bond yields (Appendix A2). Additionally, given my objective of estimating ATWACC for a new power plant, I considered a third option of secured overnight finance rates (SOFR) plus margin. SOFR is a common basis for power plant term loans and would have worked beautifully for this analysis. But true amounts were not available in Refinitiv's market intelligence database for each of the comparable companies I identified (a sample is provided in Appendix A3). In lieu of this, I estimated COD using the most-recently issued

[19] The Brattle Group. PJM CONE 2026/2027 Report. April 21, 2022. https://www.brattle.com/wp-content/uploads/2022/05/PJM-CONE-2026-27-Report.pdf.
[20] Note: long-run ERPs are approximated using arithmetic averages of historical data for the past 100 years to 1926. This seems like a specific scientific selection, but 1926 is simply the beginning year for a widely used dataset of market returns.
[21] Kroll. Kroll Cost of Capital Recommendations and Potential Upcoming Changes – March 2025 Update. March 19, 2025. https://media-cdn.kroll.com/jssmedia/kroll-images/pdfs/kroll-cost-of-capital-recommendations-and-potential-upcoming-changes-march-2025.pdf?_ga=2.107141570.1753882792.1745198419-1335826748.1745198419

corporate bonds for each company that had the closest tenor to PJM's guidance of a 20-year estimated project life.[22]

To briefly comment on COD itself, debt providers prefer consistent cash flows compared to volatile earnings when formulating their repayment terms, rates, and covenants. Lower cash flow risks and faster repayment potential translates to a lower COD. Unfortunately for power plant developers, wholesale energy market revenues are typically lumpy, meaning that project cash flows can vary meaningfully over time. This risk can be mostly offset by long-term power purchase agreements for routinely operating power plants. But a standard fossil peaker plant—which is what capacity markets have traditionally focused on—typically lacks these arrangements and has even more risk than the average pure merchant mid-merit or baseload power plant due to their low operating hours in the day-ahead and real-time energy markets. The existence of smooth and predictable capacity payments from capacity markets, therefore, should be incredibly attractive to financial lenders. Thankfully these considerations are neither solely within the realm of theory, nor only uttered in private conversations between developers and financial lenders.

Credit rating agencies explicitly consider capacity market revenues when evaluating firm credit risk. Fitch notes 'favorable near-term capacity prices' for Talen in PJM.[23,24] And S&P noted elevated PJM capacity market revenues in the first line of their October 2024 press release upgrading Vistra's credit rating to BB+, noting: "Vistra Corp. (Vistra) benefits from (...) improved Pennsylvania-New Jersey-Maryland (PJM) base residual auction (BRA) results."[25]

A 2023 report from the Institute for Energy Economics and Financial Analysis (IEEFA), a U.S.-based thinktank, observed how smooth and stable capacity market revenues—averaging $115/MW-day in the 2010s—helped fuel a boom phase in fossil plant buildouts in PJM.[26] However, fixed capacity payments themselves can vary significantly year to year.

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[22] PJM. PJM Manual 18: PJM Capacity Market Revision: 59 Effective Date: June 27, 2024. https://www.pjm.com/-/media/DotCom/documents/manuals/m18.

[23] Fitch Ratings. Fitch Revises Talen's Outlook to Negative on TL B Upsizing; Affirms Talen's IDR at 'BB-'. December 5, 2024. https://www.fitchratings.com/research/corporate-finance/fitch-revises-talen-outlook-to-negative-on-tl-b-upsizing-affirms-talen-idr-at-bb-05-12-2024

[24] Note: Despite favorable capacity market and nuclear PPA prices, Fitch downgraded Talen's credit outlook due to the company's use of debt to buyback shares while highly leveraged.

[25] S&P Global. *Vistra Corp. Upgraded To 'BB+', Outlook Stable; Recovery Rating Revised To '3' From '4' On Senior Unsecured Debt*. October 1, 2024 https://disclosure.spglobal.com/ratings/en/regulatory/article/-/view/type/HTML/id/3259995

[26] Institute for Energy Economics and Financial Analysis. Private Equity in PJM: Growing Financial Risks. By Dennis Wamsted. August 2023. https://ieefa.org/sites/default/files/2023-08/Private%20Equity%20in%20PJM%20Part%201%20Growing%20Financial%20Risks_August%202023.pdf

Fitch partially based their credit rating for Talen on an expectation of "future PJM capacity prices below $100/MW-day and energy prices around $40/MW-hr."[27]

Rather than debating Fitch's future price projections, I want to close on debt by noting that cheaper COD and higher leverage ratios are a golden ticket for power plant developers. From a purely mechanical perspective, standard DuPont decomposition of any firm's return on equity is simply a firm's return on assets multiplied by financial leverage. In other words, the higher a firm's financial leverage, the higher its return on equity. This is a mechanical fact. Combining this with financial pecking order theory—wherein firms first prioritize using cash, then debt, then equity to fund new projects—power plant companies are in a race to acquire as much leverage as possible before turning to COE financing. COD is therefore a particularly salient part for estimating an appropriate ATWACC in PJM.[28]

Data Sources for ATWACC Analysis

## ATWACC Data and Calculation

Data

Historical stock price data for AES, Vistra, NRG, Constellation, and Talen were retrieved from a combination of Yahoo finance and the Center for Research in Security Prices affiliate of the Chicago Booth School of Business. Individual company bond and loan terms were retrieved from the LSEG Data & Analytics financial market intelligence platform. Secured Overnight Financing Rate (SOFR) data was accessed via the Federal Reserve Bank of New York. Generalized corporate credit bond yields were downloaded from Bank of America corporate bond indices traded on the Intercontinental Exchange using the Federal Reserve Bank of St. Louis' economic data tool. And U.S. Treasury yields were accessed via Treasury.gov.

Calculations

The formula for calculating the weighted average cost of capital after taxes ATWACC for a project requires four inputs: COE, COD, a corporate tax rate, and the ratio of debt to equity. It is equal to:

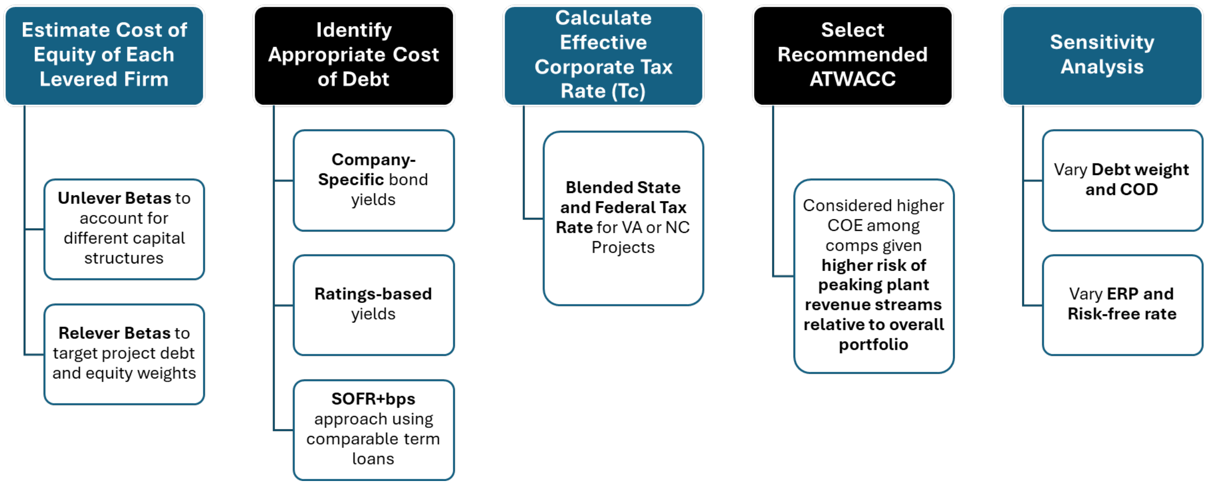
$$ATWACC = Percent\ of\ Financing\ from\ Debt \times COD\ \times (1 - Tc) + Percent\ of\ Financing\ from\ Equity\ \times COE$$

[27] Fitch Ratings. *Fitch Revises Talen's Outlook to Negative on TL B Upsizing; Affirms Talen's IDR at 'BB-'.* December 5, 2024. https://www.fitchratings.com/research/corporate-finance/fitch-revises-talen-outlook-to-negative-on-tl-b-upsizing-affirms-talen-idr-at-bb-05-12-2024

[28] Debt comes in many forms of course, and future analysis would benefit from considering differences in power plant finance assumptions across mezzanine, junior, senior, and convertible debt options.

Where $Tc$ represents the corporate income tax rate, COE is the cost of equity, and COD is the cost of debt. This was done for each firm and then rolled into one final value for ATWACC. A flowchart of my approach is as follows:

**Table 1: ATWACC Calculation Steps**




*COE*

To account for different debt-to-equity ratios across each firm, I unlevered each asset beta before re-levering them to the standard target equity-debt ratio of 55% debt and 45% equity used in comparable ATWACC estimates over the past several years.[29,30] The formulas for doing so are:

$Unlevered\ Beta = \frac{Levered\ Beta}{1-(1-Tc)\frac{D}{E}}$; and $Relevered\ Beta = Unlevered\ Beta(1 - Target\frac{D}{E}(1 - Tc))$.

Where $Tc$ represents the corporate income tax rate and $\frac{D}{E}$ is the debt-to-equity ratio of each asset. Plugging re-levered betas back into the CAPM formula provided new COEs for each firm. A table of results is included at the bottom of Appendix A1.

*COD*

Of the three options I identified for estimating COD, I used an average of company-specific bond yields assuming they would most closely reflect the costs of building a new power plant in PJM (Appendix A2). Economy-wide credit ratings were quite close to the value I selected and have a strong conceptual foundation for being applied in future analyses.

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[29]Midcontinent Independent System Operator. *MISO Cost of New Entry (CONE) and Net CONE Calculation for Planning Year 2025/2026.* September 23, 2024. https://cdn.misoenergy.org/20240923%20RASC%20Item%2003%20CONE%20and%20Net%20CONE%20Update649247.pdf

[30] This includes PJM's neighbor MISO which assumes a 55:45 ratio between debt and equity for new CTs.

Additionally, I maintained standard convention and excluded SOFR, given how most analyses of capacity market WACCs have not employed SOFR—or its predecessor LIBOR plus margin—for historic CONE estimates.

*Tax Rate*

The federal corporate tax rate in the United States at the time of writing this paper is 21%. Given my broader focus in this paper on North Carolina, I used NC's 2025 corporate tax rate of 2.25%.[31,32] From this, a combined state and federal tax rate of 22.78% was calculated for NC assuming that state corporate income tax payments would be deductible from federal corporate income tax payments.

## ATWACC Analysis Results

Putting this all together, if I was to recommend a target ATWACC to PJM today, it would be between 8.85%-9.85% to capture some risk premium spread on peaker plants relative to a general power plant portfolio (see Appendix A4 for 8.85% estimate).[33]

Comparable firm results are listed in a table below, starting with a bold value for Brattle's original PJM 2022 ATWACC recommendation to give a sense of how subsequent estimates have changed. Lazard is a clear outlier. But their number appears to be portfolio-wide and does not vary with power plant reference type—which would be expected, given the different risk profiles of cash flows of grid-scale batteries versus combustion gas turbines, for example.

**Table 2: Comparable ATWACC Assumptions**

| **Brattle Group: 8% in PJM (2022)** |
|---|

[31] North Carolina Department of Revenue. *Corporate Income Tax Rates*. Accessed April 4, 2025. https://www.ncdor.gov/taxes-forms/corporate-income-franchise-tax/corporate-income-tax-rates.
[32] Note: NC's corporate income tax rate is set to decline to 0% by 2030. Even so, the current 2.25% rate is materially lower than rates in other PJM member states. The lower end of my ATWACC recommendation would shift downward in other states—from 8.85% to 8.66% if substituting Virginia's higher 6% corporate income tax rate for instance.
[33] Each comparable company holds generalized power plant portfolios of different varieties. Net CONE is designed to approximate peaker CTs, which are riskier than a general portfolio. Hence ATWACC estimates should be biased upwards after peer comparable are analyzed.

| | |
|---|---|
| Brattle Group:<br>10.35% in ERCOT (2024) [34] | Lazard:<br>7.7% ATWACC in general 2024 LCOE+ [35] |
| Analysis Group:<br>8.96% in ISO-NE (2023) [36] | Analysis Group:<br>8.76% - 9.02% CT; 9.17% - 9.45% BESS in NYISO (2024) [37] |

While not listed in the table above, I would be remiss not to mention that by pure chance, the lower end of my current estimate exactly matches the actual ATWACC PJM filed and approved three years ago following their 2022 quadrennial review.[38]

## Discussion of ATWACC Analysis

My analysis results and sensitivity tables show how sensitive are the ATWACC estimates to future expectations about equity markets and federal reserve rates. While this does not result in an order of magnitude that rivals accelerated depreciation or federal tax credits going away, it's still material to consumers and generators alike, especially in utility areas where the PJM capacity market cleared at its maximum price ceiling. As I conducted this analysis, I also began to observe what I think is a clear feedback loop between the capacity market and real payments to capacity providers.

The ATWACC and Capacity Market Loop

Higher capacity market revenues should lead to cheaper costs of financing, which implies less "missing money" for generators. Less missing money means lower net CONE calculations, which, absent capacity bid gamification, should lead to less capacity market revenues and higher costs of financing. Higher cost of capital implies more missing money, which should lead to a repetition of this cycle.

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[34] The Brattle Group. *ERCOT CONE for 2026*. June 10, 2024. https://www.brattle.com/wp-content/uploads/2024/08/ERCOT-CONE-for-2026.pdf

[35] Lazard. Levelized Cost of Energy+. June 2024. https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf

[36] Analysis Group. *Analysis of the ATWACC of New Entry for the ISO New England Forward Capacity Market*. August 10, 2023. https://www.iso-ne.com/static-assets/documents/2023/08/a08a_mc_2023_08_08-10_fcm_netcone_updates_mopr_reforms_for_fca19_analysis_group_presentation.pdf

[37] Analysis Group, *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025-2026 through 2028-2029 Capability Years*. October 2, 2024. https://www.nyiso.com/documents/20142/47366127/Analysis-Group-2025-2029-DCR-Final-Report-Updated.pdf

[38] PJM. *Consultation With Members Regarding Future 205 Filing on Capacity Market*. November 7, 2024. Page 19. https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20241107-special/item-02---capacity-market-adjustments---presentation.ashx

However, I do not believe this steady state persists. Instead, higher capacity market revenues induce greater *threat of new entry* which leads to lower E&AS Offsets, which leads to higher risks to cash available for debt-service (CADS) and by extension, should raise a new project's cost of debt. Riskier and reduced cash flows should also demand higher equity premiums, leading the whole capital stack to an increase in cost. This can happen quickly based on auction parameters and bid behavior, putting upward pressure on Net CONE even as new supply enters the market.

Trying to manage this constant flux *almost* seem to mirror original COSR, wherein PJM will inadvertently begin to dictate the financial health of privately held competitive generators through purely administrative decisions.[39] To explore this assertion in more depth, my analysis will now turn to generator penalties and bonuses during Winter Storm Elliott.

## Renewable Generator Performance

Wind and solar generation data for the PJM portion of North Carolina were simulated to evaluate their performance during Winter Storm Elliott. While aggregate outputs from PJM's day-ahead and real-time markets were considered, the simulated approach allowed me to focus on an individual project's performance and cash flows.

Generator performance was modeled using the National Renewable Energy Lab's (NREL) System Advisor Model (SAM) version 2024.12.12. I chose the same latitude and longitude coordinates for each wind and solar generator to minimize locational differences, ultimately settling on a latitude of 39.807 and longitude of -79.3656 to mimic Amazon's *Desert Wind* installation in North Carolina. My full SAM input assumptions are listed in Appendices B1 and B2. After SAM parameters were established for each technology, I used additional NREL data for weather files.

NREL's national solar radiation database extends through to the present day, which allowed me to use hourly solar data for 2022 directly. Historic wind data was available at increments ranging from 5-minute intervals to hourly data. However, NREL's *WIND Toolkit data* only extended through 2014. Rather than build a wind speed model from scratch—given how 100m hub height wind-speed data is difficult to come by in the public domain—I instead used SAM data to simulate different historical wind profiles and compared them against the 2022 winter storm. An informal industry rule-of-thumb is to use three-to-five years of wind data to get a sense of how a site will perform. I opted for six years of wind data, ranging from 2014 to 2009.

[39] Note: a fully hedged fixed-contract PPA should offset most E&AS cash flow risks, but PJM's capacity market is focused solely on revenues obtained by purely merchant power plants.

## Simulated Wind and Solar Site Performance

Expected power plant performance has historically been calculated in PJM using an equivalent demand forced outage rate (EFORd). This assumed thermal generator outages were independently and identically distributed. However, following widespread failures during Winter Storm Elliott, all resource categories, including thermal resources, have their power generation capacity assessed via an effective load carrying capability (ELCC) calculation which considers, among other factors, positively correlated derates within each capacity resource class.[40] Wind and solar have been subject to derates for much longer though.

Prior to the 2023/2024 capacity delivery year, PJM used specific location-based derates for wind and "an average derate of 46.7%" across solar installation categories.[41] At the end of 2022, the proposed ELCCs for tracking solar was 54% and onshore wind's proposed ELCC was 15%.[42] I chose these ELCC values—which were quite close to the general range of wind derates of 13 to 16 percent of nameplate capacity—for my analysis and discussion below, believing that they reasonably approximate how PJM would think my specific latitude and longitude wind and solar resources would have delivered in 2022.

ELCC values were multiplied by installed nameplate capacities of 75 MW for each system, yielding a 11.2 MW unforced capacity (UCAP) commitment for wind and a 40.5 MW UCAP commitment for solar. These UCAP expectations form the basis for how each resource would have been expected to perform by PJM during winter storm Elliott, equal to UCAP multiplied by the Balancing Ratio for each performance assessment interval (PAI). Given my multiple years of wind data, I thought it best to visually represent them overlayed on one another graphically below. My one year of solar data can be found in Appendix B3. Finally, generator performance outputs from SAM were matched with PJM penalty and bonus rates during each PAI to determine project level impacts for each resource.

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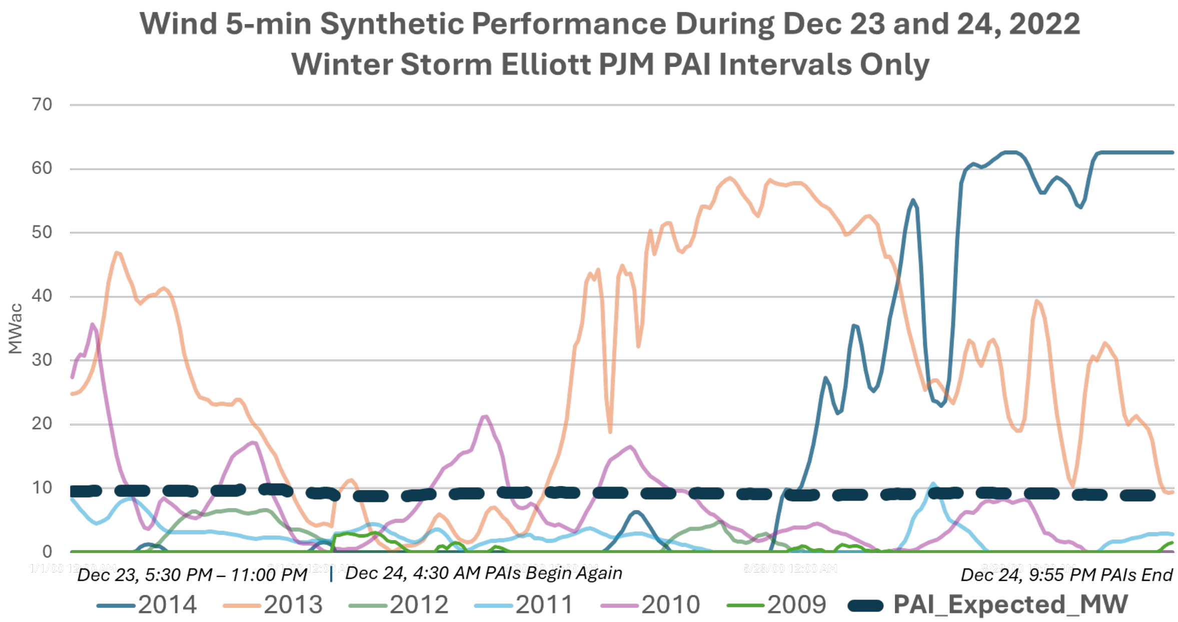
[40] PJM. ELCC Class Ratings for the 2026/2027 Base Residual Auction. Accessed April 7, 2025. https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf
[41] Monitoring Analytics. *2022 State of the Market for PJM*. March 9, 2023. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec12.pdf
[42] Ibid.

**Table 3: Five-Minute Interval Simulated Wind Performance Of 2014-2009 Weather Year Data Compared To 2022 Pais During Winter Storm Elliott**




## Estimated Financial Penalties and Bonuses

Generator financial performance during Winter Storm Elliot is a function of actual versus expected performance, five-minute RTO balancing ratios, time-varying performance bonuses ($/MW-interval), and charge rates that are specific to each LDA ($/MW-interval).

The PJM formula for calculating charge rates is equal to Net Cone ICAP * 365 days / (30 hours*12 intervals) for each LDA. Net Cone ICAP for the Dominion LDA in 2022/23 was $237.39/MW-day. So, the calculated charge rate I assumed was $240.69. Performance bonuses were equal to the balancing ratio and bonus rate at each time multiplied by resource UCAP.[43]

For example, if a resource had 10 MW of UCAP commitment, and the balancing ratio during a PAI was 90, the resource would be expected to provide 9 MW of electricity. If it generated more than 9 MW, it would receive a bonus payment. However, if the resource produced less

[43] Balancing Ratios are defined as the "the percentage share of total generation capacity commitments needed to support the load and reserves on the system within the Emergency Action area during that interval." There is a formula for calculating them, but PJM provided them directly ex-post. I used these ex-post final balancing ratio values for my analysis directly. They can be retrieved by setting the start and end dates to December 23rd and 24th for 2022 in PJM's data miner tool via https://dataminer2.pjm.com/feed/pai_final_balancing_ratio

than 9 MW during this PAI, it would owe a penalty equal to its MW deficient quantity multiplied by the charge rate for that LDA.

Bonus rates for overperformance varied throughout the storm and were publicly listed by PJM for each hour of performance interval.[44] This bonus ranged from a minimum value of $163.27/MW-day to a maximum of $216.03/MW-day, meaning that system penalties were always greater than bonuses. A table of resulting annual wind profiles, as well as the one year of solar data for 2022, are listed below:

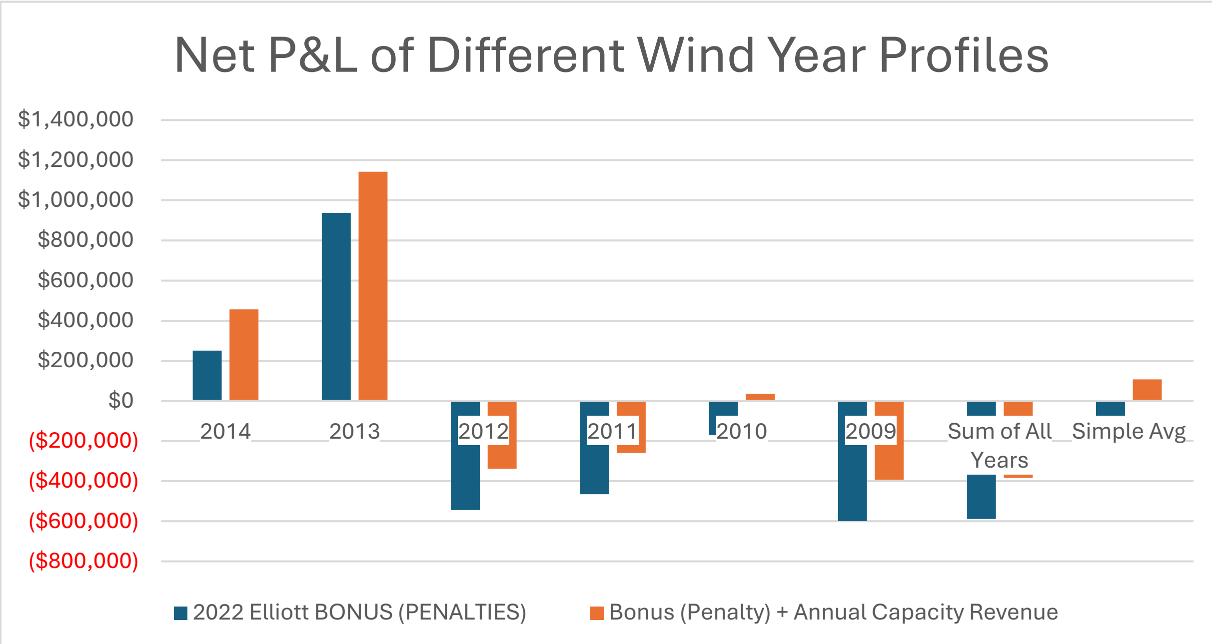
**Table 4: Simulated Wind Year Bonuses and Penalties during Winter Storm Elliott PAIs**

| Wind Data Year | 2022 Winter Storm Elliott PAI Bonuses (Penalties) |
|---|---|
| 2014 | $250,713.40 |
| 2013 | $937,573.00 |
| 2012 | ($543,624.24) |
| 2011 | ($464,756.89) |
| 2010 | ($170,029.43) |
| 2009 | ($598,666.94) |
| | |
| Net Sum | ($588,791.10) |
| Average | ($98,131.85) |

Adding back revenues received for clearing the capacity market, a summary graph of revenues plus PAI performance bonuses and penalties looks like:

[44] PJM. *Winter Storm Elliott Event Analysis and Recommendation Report*. July 17, 2023. https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf

**Table 5: Net Profit and Loss of Simulated Wind Year in 2022/23 Delivery Year**




The profile years for 2013 and 2014 wind data would have performed fantastically during Winter Storm Elliott. Whereas every other year would have received a performance penalty. PAIs are called rarely, meaning capacity resources will simply collect fixed capacity payments without much sacrifice most years. Suppose though that a generator has a liquidity concern and is terrified of receiving a penalty. The 2022/23 delivery year penalties were indexed to Net CONE ICAP, hence a natural response by generators facing this risk would be to apply upward bidding pressure to hedge future downside exposure. I list sensitivities below if wind generators had some sense of clairvoyance about the storm, employed extreme risk aversion, and only considered downside scenarios. BRA bids would have to have been almost double to triple what they cleared at in 2022/2023 to hedge this risk for wind.

**Table 6: Breakeven Wind Sensitivities**

| Breakeven Wind Sensitivities | |
|---|---|
| ICAP (MWac) | 75 |
| ELCC (%) | 15% |
| UCAPP (MWac) | 11.25 |
| | |
| $/MW-day Clearing Price | $50 |

| | |
|---|---|
| Days per Year | 365 |
| $ Revenue / MW | $18,250 |
| UCAP MWac | 11.25 |
| Annual Revenue | $205,312.50 |
| | |
| Average of Penalties Only for 2022 | ($444,269.38) |
| Breakeven BRA Price to Cover Average Penalty Risk | $108.19/MW-day |
| Worst Penalty Scenario | ($598,666.94) |
| Breakeven BRA to Cover Worse Case Scenario | $145.79/MW-day |

While these results are rough approximations of real events, I believe they show just how much room there was for prices to rise in subsequent auction years. Furthermore, while real wind generators performed excellently during Winter Storm Elliott,[45] other generators including solar and gas failed to catch the same lucky break.

**Table 7: Modeled 2022 Solar Revenues**

| | |
|---|---|
| Nameplate (MW) | 75 |
| Solar SAT ELCC | 54% |
| UCAP (MW) | 40.5 |
| | |
| $/MW-day | $50 |
| MW-days per year | 365 |
| Rev/MW | $18,250 |

[45] *Ibid.*

| | |
|---|---|
| UCAP Mwac | 40.5 |
| | |
| Annual Capacity Market Revenue | $739,125.00 |
| Winter Storm Bonus (Penalty) | ($1,733,844.79) |
| **Total Sample Solar P&L** | **($994,719.79)** |

Solar performed roughly as expected. It produced nothing during early morning or late evening PAIs. And it had lower overall output during normal operating hours on these two simulated days in December. This partly reveals why solar and wind are participating in PJM's new six-month capacity strips—solar typically performs better in summer months and wind typically performs better during winter months. The two form a partial natural hedge when paired, though BESS supporting units would improve this as well.

Pivoting back to my results, the penalties for my simulated solar site are staggering. Losing a million dollars for participating in the 2022/23 capacity market rules over something a generator cannot control is disastrous and cannot be neatly explained away to financial lenders. ELCC is a double-edged sword in this sense. Higher expected performance means higher annual revenues, but higher ELCCs also amplify negative swings during a failure to perform. In some sense, this reminds me of financial leverage. Though PJM rules are starting to change for penalties.

## Realized Penalties in PJM

Negative penalties from Winter Storm Elliot were so great that Monitoring Analytics, which serves as PJM's independent Market Monitoring Unit (MMU), declared in their 2022 Annual State of the Market Report for PJM that "payment of up to $2 billion in penalties and penalties that can exceed three times the capacity revenue for specific units do not provide useful incentives."[46] The MMU went on to note that PJM delayed performance payment collections due to fear of electric generation firm bankruptcies.

Taking this at face value, if several merchant generator developer/operating companies were facing bankruptcy, their cash flow risks would rise, their debt covenants for new power plants would tighten, equity investors would demand a higher premium, and future

[46] Monitoring Analytics. *2022 State of the Market for PJM*. March 9, 2023. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-vol2.pdf

capacity market bids and revenues would face upward pressure to compensate. Combining this observation with my analysis of ATWACC, I believe it is nearly inescapable for PJM—or any RTO trying to navigate the capacity market at present moment—to avoid playing the role of a pseudo multistate regulatory commission.

Consider the history of cost-of-service regulation (COSR), whose seminal cases include FPC v. Hope Natural Gas Co. (1944) and Bluefield Water Works & Improvement Co. v. Public Service Commission (1923). Both cases concerned the financial integrity of utility companies compensated via COSR. Fast forward to modern capacity markets, and PJM includes in its analysis an implicit reasonable rate of return for generators across its territory when calibrating not just ATWACC but also realized penalties for non-performance. Again, like traditional COSR cases including Jersey Central (1987) or Duquesne Light Company v. Barasch (1989), a difference is being split between ratepayer costs and generator profits. And just like those cases, private suppliers—like the utility companies of old—are being partially sheltered from market forces.

I would like to offer one bright spot for PJM though. PJM's new penalty policy direction is quite different than it was during the 2022/23 delivery year. PJM has changed the maximum penalty to capacity providers from 1.5x Net Cone ICAP to "1.5 times the RPM Base Residual Auction clearing price applicable to the modeled LDA in which the resource resides."[47] Under the old rule, the maximum penalty for my solar site was $5,263,826.51. Under the new rule, the cap would be $1,368,750.

This change should cause a huge sigh of relief for generators of all types, especially poorly performing gas units. That said, I believe this fixes a perverse incentive for generators to artificially bid high values to offset the risk of PAI penalty charges that only considered Net CONE and not clearing prices. Even so, despite this positive change, I believe generators are still going to bid higher values in the short-term to make up for larger unanticipated penalties during 2022, which are of course layered onto previous missing money expectations. Meaning that while this is a good long-term fix, it only partially reduces short-term incentives for higher than usual bids. Furthermore, given that all resources capacities (and therefore capacity-market payments) have now been derated via ELCC, old thermal plants are going to bid even higher. And so too will wind and solar resources in my opinion.

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[47] PJM. *PJM Manual 18: PJM Capacity Market Revision: 59 Effective Date: June 27, 2024. Redline copy. Page 188.* https://www.pjm.com/-/media/DotCom/documents/manuals/m18-redline.pdf

## Conclusion

Like FERC Commissioner Christie, I believe PJM deserves more credit than they are often given.[48] This most recent winter storm season was a relative success. PJM avoided blackouts even amidst high unforced outage rates.[49]

Nevertheless, I wish to point out that the underlying temptation of states who have whispered about returning to regulated markets should not come as a surprise. After all, PJM's capacity market is in some sense mimicking compensation structures of the old system of utility rate regulation via out-of-market payments, administrative financial relief to capacity providers, and state interventions. Should high prices persist, it takes little imagination to consider how states might rethink their decision to restructure generation and re-examine whether to stay in ISO/RTOs altogether.

In closing, should states decide to stick with the ISO/RTO model, it is expected that capacity markets will continue to grow in importance, unless there is an overhaul of day-ahead and real-time energy markets. If E&AS revenues fall over time with high penetration of zero-to-low marginal cost renewable energy resources, either (1) price caps will have to rise for batteries and thermals to cover their fixed costs through energy market participation, or (2) capacity market prices will have to rise again to compensate.[50] Should the later happen, ATWACC calculations and performance penalties will become even more relevant over time.

It was a pleasure learning a small amount about these markets. I wish market participants, PJM, and ratepayers all the best of luck. And I look forward to reviewing the BRA capacity auction results two months from now in July.

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[48] Ethan Howland. Cold-weather grid performance improves, plus 4 other FERC open meeting takeaways. Utility Dive. April 18, 2025. https://www.utilitydive.com/news/ferc-nerc-cold-weather-grid-performance-pjm-data-centers/745751/

[49] FERC. *January 2025 Arctic Events A System Performance Review.* Joint staff report by FERC, NERC, and its Regional Entities. April 17, 2025 https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional

[50] Renewable energy projects near $0/MWh marginal cost are benefitting from high thermal clearing prices now. As more renewables get added to the grid, and if thermal generation—specifically, coal and natural gas power plants—continue to retire, there will be less revenues to go around to all participants. I believe this will either change bid behaviors drastically, revitalize the old bilateral system of trading through forward capacity procurements, or naturally lend itself towards more emphasis on current capacity markets—wherein secondary market payments account for 'missing' revenues to keep participants financially afloat and able to fulfill their debt covenants. Batteries ameliorate this to some degree. But the next target for reform will then become price caps. And the search for missing money will begin all over again.

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| Mark Drouillard | Financial Database Advice |

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# Appendices

Appendix A1 – Comparable Firms Analysis

| | TALEN | Constellation | AES | VISTRA | NRG |
|---|---|---|---|---|---|
| Betas from Refinitiv | 1.47 | 1.56 | 0.94 | 1.25 | 1.05 |
| Beta Calculation Frequency | 2Y Weekly | 2Y Weekly | 5Y Monthly | 5Y Monthly | 5Y Monthly |
| ERP | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| Rf | 3.86% | 3.86% | 3.86% | 3.86% | 3.86% |
| CAPM COE | 11.21% | 11.66% | 8.56% | 10.11% | 9.11% |
| | | | | | |
| Market Cap ($ billions) | 7.94 | 53.56 | 7.67 | 33.36 | 17.03 |
| 2024 ROEs from Refinitiv (background not used in analysis) | 51.67% | 30.11% | 11.82% | 51.57% | 41.79% |
| | | | | | |
| **Company Equity Debt Splits** | *TALEN* | *Constellation* | *AES* | *VISTRA* | *NRG* |
| Total Equity | 1,387 | 13,539 | 7,704 | 5,583 | 2,478 |
| Total Liabilities | 4,719 | 39,387 | 39,702 | 32,187 | 21,544 |
| Sum Total | **6,106** | **52,926** | **47,406** | **37,770** | **24,022** |
| | | | | | |
| Long-Term Debt (LTD) | 2,987 | 7,384 | 25,216 | 15,418 | 9,812 |
| Current Portion of LTD | 17 | 1,028 | 3,578 | 880 | 996 |
| Total Debt | **3004** | **8412** | **28794** | **16298** | **10808** |
| Debt to Equity Ratio | **216.6%** | **62.1%** | **373.8%** | **291.9%** | **436.2%** |
| E/V | **0.32** | **0.62** | **0.21** | **0.26** | **0.19** |
| D/V | **0.68** | **0.38** | **0.79** | **0.74** | **0.81** |
| | | | | | |
| **Unlevering Betas** | *TALEN* | *Constellation* | *AES* | *VISTRA* | *NRG* |
| Levered Betas | 1.47 | 1.56 | 0.94 | 1.25 | 1.05 |
| D/E | **2.17** | **0.62** | **3.74** | **2.92** | **4.36** |
| Corporate Tax Rate (retrieved from Refinitiv) | 21.7% | 21.7% | 21.7% | 25.4% | 25.0% |
| Unlevered Betas | **0.55** | **1.05** | **0.24** | **0.39** | **0.25** |
| | | | | | |
| **Relevering Betas to Target Project Debt and Equity Weights** | *TALEN* | *Constellation* | *AES* | *VISTRA* | *NRG* |
| Target D/E | **1.22** | **1.22** | **1.22** | **1.22** | **1.22** |
| Target Weight Equity | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 |
| Target Weight Debt | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 |
| Generic Target Tc for PJM RTO | 25.7% | 25.7% | 25.7% | 25.7% | 25.7% |
| Target Tc for NC Dominion | **22.78%** | **22.78%** | **22.78%** | **22.78%** | **22.78%** |
| Re-levered Betas for NC | **1.06** | **2.04** | **0.47** | **0.76** | **0.48** |

| New CAPM Calculations | TALEN | Constellation | AES | VISTRA | NRG |
|---|---|---|---|---|---|
| Re-levered Beta NC | 1.06 | 2.04 | 0.47 | 0.76 | 0.48 |
| ERP | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| Rf | 3.86% | 3.86% | 3.86% | 3.86% | 3.86% |
| Re-levered CAPM COE | **9.16%** | **14.06%** | **6.18%** | **7.68%** | **6.25%** |

| Cost of Debt Sensitivities | TALEN | Constellation | AES | VISTRA | NRG |
|---|---|---|---|---|---|
| COD Company-Specific Yields | 6.53% | 5.23% | 5.80% | 5.71% | 6.39% |
| COD Credit Rating Yields | 5.97% | 5.42% | 5.42% | 5.97% | 5.97% |
| COD SOFR+bps | 7.02% | 6.62% | N/A | N/A | N/A |

Note: *Blue numbers above indicate calculated values. Debt and equity ratios were visually pulled by author using public Financial Statements, the SEC form 10K, for fiscal year 2024. This ended February 28 for each company. AES does not explicitly name its 'long-term debt' in their shareholder reports or financial reports, so its overall corporate 'Debt Obligation' value was used for simplicity. Credit-based yields were pulled from ICE BofA US Corporate Index Effective Yields at spot values for BB and BBB ratings (AES and Constellation being the most credit worthy at BBB and the rest at BB).*

Appendix A2 – Corporate Bond Yields

| | Talen | Constellation | AES | Vistra | NRG |
|---|---|---|---|---|---|
| **Issue Date** | May-23 | Sep-23 | Mar-25 | Dec-24 | Oct-24 |
| **Maturity** | 2030 | 2034 | 2032 | 2034 | 2034 |
| **Yield** | 6.53% | 5.23% | 5.80% | 5.71% | 6.39% |

Appendix A3 - Example SOFR + bps rates from Talen's 10K annual financial disclosure

| | | |
|---|---|---|
| **TLB-1** | 7.02% | SOFR + 250 basis points |
| **TLB-2** | 7.02% | SOFR + 250 basis points |
| **Secured Notes** | 8.63% | SOFR + 200 basis points |

Appendix A4 – ATWACC Model Output

| ATWACC Model Output | | | |
|---|---|---|---|
| | **Pre-Tax WACC** | **ATWACC** | **Description** |
| Base Case | 7.16% | 6.42% | Average COE, Average Corp Bond Yield, 45% Equity Funds 55% Debt Funds |
| Ratings COD | 7.18% | 6.43% | Average COE, Ratings-Based Cost of Debt, 45% Equity Funds 55% Debt Funds |
| SOFR+250bps COD | 7.69% | 6.83% | Average COE, SOFR+Bps Cost of Debt, 45% Equity Funds 55% Debt Funds |
| Max COE | 9.59% | 8.85% | Max COE Among Peer Group, Average Corp Bond Yield, 45% Equity Funds 55% Debt Funds |

Appendix A5 - Max COE Scenario used in Sensitivity Analysis

| Max COE Scenario used in Sensitivity Analysis | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | Expected ERP [Rm- Rf] | | | | | |
| | | 0.045 | 0.050 | 0.055 | 0.060 | 0.065 | 0.070 |
| RF | 0.035 | 8.2% | 8.7% | 9.1% | 9.6% | 10.1% | 10.5% |
| | 0.039 | 8.4% | 8.8% | 9.3% | 9.8% | 10.2% | 10.7% |
| | 0.040 | 8.5% | 8.9% | 9.4% | 9.8% | 10.3% | 10.7% |
| | 0.045 | 8.7% | 9.1% | 9.6% | 10.1% | 10.5% | 11.0% |
| | 0.050 | 8.9% | 9.4% | 9.8% | 10.3% | 10.7% | 11.2% |
| | 0.055 | 9.1% | 9.6% | 10.0% | 10.5% | 11.0% | 11.4% |
| | 0.060 | 9.4% | 9.8% | 10.3% | 10.7% | 11.2% | 11.6% |

*Gray values above are sensitivities using my defaults for Rf and ERP. Blue highlights are my guess as to which quadrant subsequent consultant reviews will end up—given how frequently they list considerably higher ERPs compared to what's publicly available on Duff & Phelps. If I had access to this private forward-looking database, my base case may well have ended up in the same area. As of 4/7/2025, presented during my in-person discussion, I selected the yellow highlighted cell of 9.6% which aligns better with longer term treasury yields and higher ERPs. Recent tariff policy changes will likely shift this and complicate it further.*

Appendix A6 - ATWACC Sensitivity to Varying Debt Shares and Values

| **ATWACC Sensitivity to Varying Debt Shares and Values** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | Debt Weight | | | | | |
| | | 0.450 | 0.500 | 0.550 | 0.600 | 0.650 | 0.700 |
| Cost of Debt | 3.00% | 7.9% | 7.7% | 7.6% | 7.5% | 7.3% | 7.2% |
| | 4.00% | 8.2% | 8.1% | 8.0% | 7.9% | 7.8% | 7.7% |
| | 5.00% | 8.6% | 8.5% | 8.4% | 8.4% | 8.3% | 8.3% |
| | 5.93% | 8.9% | 8.9% | 8.8% | 8.8% | 8.8% | 8.8% |
| | 6.00% | 8.9% | 8.9% | 8.9% | 8.9% | 8.8% | 8.8% |
| | 7.00% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.4% |
| | 8.63% | 9.8% | 9.9% | 10.0% | 10.1% | 10.2% | 10.2% |

*Gray values above are sensitivities using my default COD and project debt-to-equity weights. The 8.63% COD row reflects the highest observed value among comparable firms, which was Talen's Secured Note of 8.63% reported as SOFR + 200 basis points. In crude terms, one can observe how ATWACC falls as the weight of debt rises. Theoretically, Modigliani and Miller's theorem should imply that cost of equity would increase correspondingly to offset this use of greater financial leverage. Further analysis should therefore consider adjustments such as the inclusion of debt betas and the risk premium of firm bankruptcy as debt share increases, which would result in upward pressure on ATWACC.*

Appendix A7 - Considerations for Including Talen in List of Comparable Public Firms

Despite Talen having limited recent public stock data, they are among the best fitting comparable firms for merchant capacity development in PJM. Planned retirements of Talen's Brandon Shores and Wagner plants, originally slated for 2025 but recently postponed to 2029,[51] shaped PJM's BGE zone clearing price by failing to be added to that LDA's UCAP offer supply curve.[52] So despite the company's lower observation counts for individual stock return variance and covariance with the broader market, I believe their inclusion is meaningful. The company's historic stock returns from 2015-2019 were contemplated, but post-2023 IPO Talen appears to be valued as a fundamentally different

[51] https://ir.talenenergy.com/news-releases/news-release-details/talen-energy-other-parties-reach-reliability-must-run-settlement
[52] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240927-5073&optimized=false

company than previously due to the confluence of their financial restructuring, public re-offering, and new fundamental power demand from technology companies.

Appendix B1 - Full NREL SAM Input Assumptions for Wind

*Same system for every year of weather data model runs from 2014-2009.*

| NREL SAM Wind Assumptions | Value | Note |
|---|---|---|
| **Rated Output** | 1,500 kW | Default for selected turbine model |
| **Rotor Diameter** | 77 m | Default for selected turbine model |
| **Hub Height** | 100 m | Average hub height based upon DOE Land-Based Wind Market Report_2024[53] |
| **Shear Coefficient** | 0.14 | Default NREL SAM assumption. Higher shear coefficients should lead to greater capacity factors.[54] |
| **Turbine Type** | GE 1.5sle | GE found to have majority market share in 2024 DOE Land-Based Wind Market Report—see figure 14 '*Annual U.S. market share of wind turbine manufacturers by MW, 2005–2023*'. The 1.5sle model was selected due to it being one of three defaults for GE turbine power curves in NREL SAM's built-in turbine library. |
| **Farm Size** | 75 MW | 100 MW is a standard sample plant size, but given the 1.5 MWac increments on the turbine model, 75 MWac was selected instead. Solar MWac was sized to match this as well to keep the analysis uniform between the two resources. Plus, 75 MWac aligns with the soft cap on projects seeking to operate via PURPA. |
| **Number of Turbines in Farm** | 50 | Desired 75 MWac / 1.5 MWac nameplate per turbine |
| **Installed Nameplate Capacity** | 75 | Same as Farm Size. |
| **Wake Effects** | Simple Wake Model | Default Value |
| **Turbulence Coefficient** | 0.1 | Default Value |

[53] https://emp.lbl.gov/sites/default/files/2024-08/Land-Based%20Wind%20Market%20Report_2024%20Edition.pdf
[54] https://www.sciencedirect.com/science/article/pii/S0196890405000142

| | | |
|---|---|---|
| **Constant Loss Wake Effect** | 11.02% | Default Value (Unchangeable) |
| **Losses Tab** | All Defaults | Includes wake losses, availability losses, electrical losses, turbine performance losses, environmental losses, and curtailment/operational strategies losses.<br><br>Default curtailment values were small, and my overall capacity factor was roughly in line with the real published values for this location. Therefore, I did not adjust this section. Fuller analysis would benefit from adjusting this upward or downward based on PJM's future observed dispatch orders during comparable winter storms. |

Appendix B2 - Full NREL SAM Input Assumptions for Simple Solar (2022 weather file)

| NREL SAM Solar Assumptions | Value | Note |
|---|---|---|
| **System Nameplate Capacity** | 100,500 kWdc | Match wind by dividing target nameplate capacity of 75 MWac by the ILR ratio of 1.34, which yielded a 100.5 MWdc system. |
| **Module Type** | Standard | Default |
| **DC to AC ratio** | 1.34 | Assumed in the NREL ATB for 2024.[55] |
| **Rated Inverter Size** | 96% | NREL ATB 2024 Conservative Scenario. |
| **Array Type** | 1-axis tracking | LBNL data shows how single axis trackers, SATs, have dominated new solar installations for some time now.[56] |
| **Tilt** | 0 | For SAT |
| **Azimuth** | 180 | South facing to maximize annual capacity factor (not always optimal, but |

[55] https://atb.nrel.gov/electricity/2024/utility-scale_pv
[56] https://emp.lbl.gov/sites/default/files/emp-files/utility_scale_solar_2023_edition_slides.pdf - Page 15.

| | | |
|---|---|---|
| | | assuming this would represent a standard site). |
| **Ground coverage ratio** | 0.3 | Default SAM Assumption |
| **System Losses** | SAM Defaults | Includes 2% soiling, 3% shading, 0% snow, 2% mismatch, 2% wiring, 0.5% connections, 1.5% light-induced degradation, 1% nameplate degradation, 0% aging (not quite applicable given this was 1-year on a model run), 3% availability; for total losses of 14.08%. |
| **Grid Limits** | 75MWac | I was unsure how SAM would handle IX limit violations if DC power climbed above 75 MW, so I included an AC cap to hedge against this violation. Likely not needed for future analysis. But played it safe. |

Appendix B3 - Hourly Simulated Solar Performance Joined with PAI Counts and Ratios

| Hour Beginning | Solar_MW | Average Balancing Ratio | PAI Count |
|---|---|---|---|
| **12/23/2025 0:00** | 0 | | |
| **12/23/2025 1:00** | 0 | | |
| **12/23/2025 2:00** | 0 | | |
| **12/23/2025 3:00** | 0 | | |
| **12/23/2025 4:00** | 0 | | |
| **12/23/2025 5:00** | 0 | | |
| **12/23/2025 6:00** | 0 | | |
| **12/23/2025 7:00** | 1.01 | | |
| **12/23/2025 8:00** | 9.70 | | |
| **12/23/2025 9:00** | 11.08 | | |
| **12/23/2025 10:00** | 19.51 | | |
| **12/23/2025 11:00** | 24.03 | | |
| **12/23/2025 12:00** | 32.43 | | |
| **12/23/2025 13:00** | 29.41 | | |
| **12/23/2025 14:00** | 31.91 | | |
| **12/23/2025 15:00** | 37.91 | | |
| **12/23/2025 16:00** | 1.37 | | |

| | | | |
|---|---|---|---|
| **12/23/2025 17:00** | 0 | 84.86 | 6 |
| **12/23/2025 18:00** | 0 | 85.62 | 12 |
| **12/23/2025 19:00** | 0 | 85.49 | 12 |
| **12/23/2025 20:00** | 0 | 85.59 | 12 |
| **12/23/2025 21:00** | 0 | 87.92 | 12 |
| **12/23/2025 22:00** | 0 | 83.02 | 12 |
| **12/23/2025 23:00** | 0 | | |
| **12/24/2025 0:00** | 0 | | |
| **12/24/2025 1:00** | 0 | | |
| **12/24/2025 2:00** | 0 | | |
| **12/24/2025 3:00** | 0 | | |
| **12/24/2025 4:00** | 0 | 78.03 | 7 |
| **12/24/2025 5:00** | 0 | 78.20 | 12 |
| **12/24/2025 6:00** | 0 | 80.48 | 12 |
| **12/24/2025 7:00** | 1.06 | 82.41 | 12 |
| **12/24/2025 8:00** | 20.28 | 83.16 | 12 |
| **12/24/2025 9:00** | 1.63 | 83.01 | 12 |
| **12/24/2025 10:00** | 8.06 | 82.40 | 12 |
| **12/24/2025 11:00** | 26.43 | 81.99 | 12 |
| **12/24/2025 12:00** | 23.15 | 81.77 | 12 |
| **12/24/2025 13:00** | 11.42 | 80.74 | 12 |
| **12/24/2025 14:00** | 27.74 | 79.35 | 12 |
| **12/24/2025 15:00** | 29.32 | 79.94 | 12 |
| **12/24/2025 16:00** | 1.75 | 81.58 | 12 |
| **12/24/2025 17:00** | 0 | 82.30 | 12 |
| **12/24/2025 18:00** | 0 | 82.04 | 12 |
| **12/24/2025 19:00** | 0 | 81.20 | 12 |
| **12/24/2025 20:00** | 0 | 79.61 | 12 |
| **12/24/2025 21:00** | 0 | 79.14 | 12 |
| **12/24/2025 22:00** | 0 | | |
| **12/24/2025 23:00** | 0 | | |

Appendix C – Illustrative Solar and Wind Output using NREL SAM for the Same Site

*Illustrates how wind and solar generation may complement each other's capacity commitments, with wind speeds ranging higher during winter months and solar during summer months. This same relationship applies to night and daylight cycles as well.*