EARTHJUSTICE

June 9, 2025

VIA ELECTRONIC FILING

Adam J. Teitzman
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Re: Docket No. 20250011-EI - Petition for rate increase by Florida Power Light & Company.

Dear Mr. Teitzman,

On behalf of Intervenors Florida Rising, League of United Latin American Citizens of Florida, and Environmental Confederation of Southwest Florida, Inc., I have enclosed the testimony and exhibits of Karl R. Rábago. Please file these documents in Docket No. 20250011-EI. Please contact me if there are any questions regarding this filing.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy and correct copy of the foregoing was served on this 9th day of June 2025, via electronic mail on:

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DATED this 9th day of June 2025.

/s/ Bradley Marshall
Attorney

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	)))	DOCKET NO. 20250011-EI

DIRECT TESTIMONY

OF KARL R. RÁBAGO

ON BEHALF OF

FLORIDA RISING, INC.,

LEAGUE OF UNITED LATIN AMERICAN CITIZENS,

AND

ENVIRONMENTAL CONFEDERATION

OF SOUTHWEST FLORIDA, INC.

JUNE 9, 2025

I. INTRODUCTION AND OVERVIEW

Q. Please state your name, business name, and address

A. My name is Karl R. Rábago. I am the principal of Rábago Energy LLC, a Colorado limited liability company, located at 1350 Gaylord Street, Denver, Colorado.

Q. On whose behalf are you appearing in this proceeding?

A. I appear here in my capacity as an expert witness on behalf of Florida Rising, Inc. ("FL Rising"), LULAC Florida Inc., better known as the League of United Latin American Citizens of Florida ("LULAC"), and the Environmental Confederation of Southwest Florida, Inc. ("ECOSWF").

Q. Please list your formal educational degrees.

A. I earned a Bachelor of Business Administration in Management from Texas A&M University in 1977, a Juris Doctorate with Honors from The University of Texas School of Law in 1984, a Master of Laws in Military Law from the U.S. Army Judge Advocate General's School in 1988, and a Master of Laws in Environmental Law from the Pace University Elisabeth Haub School of Law in 1990.

Q. Please summarize your experience and expertise in the field of electric utility regulation.

A. I have worked for 35 years in the utility industry and related fields, following my honorable discharge from the U.S. Army, where I served as an Armored Cavalry officer and a Judge Advocate. I am actively involved in a wide range of utility regulatory and ratemaking issues across the United States. My previous employment experience includes Commissioner with the Public Utility Commission of Texas, Deputy Assistant Secretary with the U.S. Department of

Energy, Vice President with Austin Energy, Executive Director of the Pace Energy and Climate Center, Managing Director with the Rocky Mountain Institute, and Director with AES Corporation, among others. For the past fourteen years, I have operated Rábago Energy LLC as a vehicle for my consulting and expert witness work. My resume is attached as Exhibit KRR-1.

Q. Have you ever testified before the Florida Public Service Commission ("Commission") or other regulatory agencies?

A. I have submitted testimony before the Commission in the past in several proceedings, including the Florida Energy Efficiency and Conservation Act ("FEECA") proceedings in 2014 (Docket Nos. 130199-EI, 130200-EI, 130201-EI, and 130202-EI), the Florida Power & Light need determination case for the Okeechobee Plant (Docket No. 150166-EI), the Gulf Power general rate case in 2017 (Docket No. 160186-EI), the Duke Energy Florida "Clean Energy Connection" program application (Docket No. 20200176-EI), the Florida Power & Light Company general rate case in 2021 (Docket No. 20210015-EI), the Tampa Electric Company general rate case (Docket No. 20240026-EI), and the Duke Energy Florida general rate case in 2024 (Docket No. 20240025-EI). In the past fourteen years, I have submitted testimony, comments, or presentations in proceedings in Alabama, Arkansas, Arizona, California, Colorado, Connecticut, District of Columbia, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Hampshire, New York, North Carolina, Ohio, Pennsylvania, Puerto Rico, Rhode Island, Vermont, Virginia, Washington, and Wisconsin. I have also testified before the U.S. Congress and have been a participant in comments and briefs filed at several federal agencies and courts. A listing of my previous testimony is attached as Exhibit KRR-2.

Q. Does your experience give you insights into the responsibilities and duties of the Commission in this proceeding?

A. Yes. As a public utility commissioner in Texas, I participated in making decisions on hundreds of rate review, rulemaking, and planning decisions in cases involving investor-owned, municipal, and cooperative electric and telephone utilities. Those matters ranged widely, from ministerial annual interest rate approvals, for example, to prudence and rate decisions on a $12.4 billion nuclear power plant, to mergers and acquisitions. I have appeared before hundreds of commissioners and board members in formal, informal, and educational proceedings in the years since. I have contributed to the writing and passage of laws and rules in many jurisdictions and have made a career of advancing regulatory and market opportunities for competitive alternatives to monopoly control of essential services businesses, especially through the expanded deployment and use of distributed energy resources. I am honored to have served as a utility regulator and remain deeply respectful of the public interest obligation that comes with the job.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to share my evaluation of the proposal for rate increases, rate changes, planning approaches, resource investments, earnings growth mechanisms, and other requests submitted by Florida Power and Light ("FPL") in this proceeding seeking rate increases and approval of several regulatory requests (the "petition"). I will address several ways in which FPL seeks the support and approval of the Florida Public Service Commission ("Commission") to impose unreasonable and unnecessary financial burdens and hardships on residential customers. I offer recommendations to the Commission for ways that these burdens and hardships can be lessened to ensure that fair, just, and reasonable rates flow from this proceeding, and for ways that the Commission can and should exercise its authority to reign in FPL's abuses.

Q. How would you characterize, at a high level, the Company's proposals in this proceeding?

A. The Company proposes rate changes and other actions that unnecessarily, unreasonably, and unjustly seek to enrich its stockholders at the expense of its customers and the environment. The Company's application proposes a four-year rate plan covering the years 2026-2029 and includes proposals for nearly $4 billion in additions to base revenue requirements due to capital spending in 2026 and 2027 and after adjustments results in $2.5 billion in new revenue requested, as well as investments in 2028 and 2029 in more generation and other infrastructure that FPL will seek to recover through the Solar Base Rate Adjustment ("SoBRA").[1]

Table KRR-1: FPL Proposed Revenue Requirement Increases

	2026	2026 Share of Requested Revenue Increase	2027	2027 Share of Requested Revenue Increase	2026 and 2027
Capital Initiatives	$1,839,000,000	63%	$809,000,000	78%	$2,648,000,000
Loss of Reserve Amortization	$336,000,000	11%			$336,000,000
Cost of Capital	$256,000,000	9%	$31,000,000	3%	$287,000,000
Unprotected Excess ADIT Amortization	$167,000,000	6%	$27,000,000	3%	$194,000,000
Inflation & Customers Growth	$134,000,000	5%			$134,000,000
Depreciation Expense Increases	$122,000,000	4%			$122,000,000
Dismantlement Funding Increases	$56,000,000	2%			$56,000,000
Other Revenue Requirement Increases	$24,000,000	1%			$24,000,000
Net IRA Tax Credits			$169,000,000	16%	$169,000,000
	$2,934,002,026	**100%**	**$1,036,000,000**	**100%**	**$3,970,002,026**

Source: Laney Direct Ex. IL-7, -11

[1] Direct testimony of FPL witness Ina Laney ("Laney Direct") at IL-7, IL-11.

Capital initiatives account for two-thirds of the total proposed revenue growth in 2026 and 2027. A major factor driving rate and cost increases, and proposed shareholder profits, is an unreasonable request for a return on equity ("ROE") of 11.9% and an equity ratio of over 59%—all at a time when industry ROEs are trending below 10% and the cost of debt remains much lower than FPL's current and requested ROE—which increases revenues by $287,000,000. In several other ways, the Company proposes to make itself a haven for overearning, including proposals for authority to continue to manipulate tax liabilities and tax credits to ensure continued maximum earned ROE. Again, FPL proposes to continue its excessive capital spending through its SoBRA mechanism to add even more to rate base in 2028 and 2029.

Q. What rate making principles offer guidance for the Commission's evaluation of FPL's application and the issues in this proceeding?

A. For nearly 65 years, James Bonbright's treatise entitled "Principles of Public Utility Rates" has stood as a foundational reference for evaluation of rate making proposals and approaches.[2] The following articulation of the Bonbright principles[3] is useful in general and in reviewing the Application:

- Rates should be characterized by simplicity, understandability, public acceptability, and feasibility of application and interpretation.
- Rates should be effective in yielding total revenue requirements.
- Rates should support revenue and cash flow stability from year to year.
- Rate levels should be stable in themselves, with minimal unexpected

[2] James C. Bonbright, *Principles of Public Utility Rates* (Columbia Univ. Press 1961), available at: https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/.

[3] This summary was derived from Jess Totten, *Tariff Development II: Rate Design for Electric Utilities,* Briefing for NARUC/INE Partnership (Feb. 1, 2008), https://pubs.naruc.org/pub.cfm?id=538EA65C-2354-D714-5107-44736A60B037.

changes that are seriously averse to existing customers.

- Rates should be fair in apportioning cost of service among different consumers.
- Rate design and application should avoid undue discrimination.
- Rates should advance economic efficiency, promote the efficient use of energy, and support market growth for competing products and services.

Ways in which FPL's proposals are inconsistent with these proposals will be discussed in the body of this testimony. As they have for decades in hundreds if not thousands of rate proposals across the country and around the world, the Bonbright Principles provide a useful starting point for reviewing FPL's rate proposals.

Q. What law and regulatory precedent guides the Commission decision in this matter?

A. Under Florida law,[4] no utility may charge or receive, directly or indirectly, any rate that is unfair, unjust, or unreasonable. No utility may make or give any undue or unreasonable preference or advantage to any person or locality or subject any person to undue or unreasonable prejudice or disadvantage. In short, Florida law charges the Commission with approving only those rates that are fair, reasonable, and just. In setting rates, the Commission must investigate and determine the prudent costs of utility investments and other spending used and useful in providing electric service and serving the public interest.

Q. What specific elements of the Company's proposals do you address in this testimony?

[4] Fla. Stat. §§ 366.03, 366.06 (2024).

A. My testimony focuses on a few key issues of greatest significance to FL Rising, ECOSWF, and LULAC. Those are proposals by the Company to increase rates and charges that these organizations and their members will have to pay for electric service over the term of the proposed rates. The issues addressed are:

- FPL's proposal to move to a 12-coincident peak, 25% energy allocator for production costs.
- FPL's proposed return on equity and proposed capital structure, particularly the equity ratio.
- FPL's proposals for new capital spending, including to build unnecessary new battery facilities, and to rely on dubious procedures for characterizing resource adequacy risks.
- FPL's proposal to install 522 MW of battery in Northwest Florida in 2025.
- FPL's proposal to implement a new Tax Adjustment Mechanism ("TAM") that would create an FPL-controlled non-cash accounting mechanism to accelerate the recognition of deferred tax liability reductions so as to maximize profits.
- FPL's proposal to deceptively dampen the short-term impacts of excessive investments in battery facilities by realizing investment tax credits ("ITCs") in a single year and in violation of the matching principle of rate making.
- FPL's proposal to continue the economically regressive minimum bill mechanism and increase it by 20%, from $25 to $30.
- FPL's proposed Large Load rate schedules.
- FPL's proposal to make permanent its Solar Power Facilities Program.

- FPL's energy sales forecasting.

The one consistent theme connecting each of these issues is that customer bills and rates are higher than they should be and will continue to be so.

Q. FPL witness Cohen offers testimony that FPL typical residential bills are substantially lower than the average for other utilities.[5] Is this a valid assertion that the Commission and customers may rely on?

A. There is no reasonable basis for accepting witness Cohen's assertion, even though it is repeated by several FPL witnesses. The claim that FPL rates are lower than the national average bills for customers using 1,000 kWh per month misrepresents the average usage level of FPL customers, which is substantially greater than 1,000 kWh per month, and ignores the average monthly consumption levels in many other states. Witness Cohen's claim appears to be based on data from a proprietary study published by the Edison Electric Institute, only available to the public at a significant price, and for which methods and sources are not provided. And it appears out of sync with data that FPL and other regulated electric utilities provide in official reports to the U.S. government.

Q. Is there publicly available data that reflects where FPL rates stand?

A. The U.S. Energy Information Administration ("EIA"), which provides independent statistics and analysis based on utility FERC Form 1 and other reports, collects and reports electric sales, revenue, and price information to the public free of charge. According to the EIA-reported data for residential sales

[5] Direct testimony of FPL witness Tiffany C. Cohen ("Cohen Direct") at 6.

and prices,[6] FPL average customer bills are much higher than FPL represents. According to this self-reported utility data, average residential monthly usage is 1,133 kWh, more than 10% higher than the 1,000 kWh "typical bill" used by FPL. And the average rate for residential electric service is 15.01 cents per kWh, yielding an average monthly bill of $170.14.[7] This monthly bill amount is almost $50 more per month, or 40% higher, than the monthly bill FPL presents from industry association data and based on 1,000 kWh of monthly use.[8]

The EIA Data shows that when utility-specific usage rates, prices, and revenues are used, FPL residential customers pay the twelfth highest electric bills nation-wide, out of more than 180 investor-owned electric utilities.[9]

Q. How will FPL's proposals in this case impact residential customer bills?

A. FPL will most likely move even higher up in the rankings for highest bills if the Commission approves FPL's rate increases. For 2026, FPL proposes to increase the fixed customer charge by nearly 14%, from $9.61 per customer per month to $10.92,[10] and to increase the minimum bill for non-demand charge customers from $25 per customer per month to $30.

FPL further proposes to increase the volumetric energy charges for residential customers, and in an economically regressive way. FPL proposes that the base energy charge for a customer's first 1,000 kWh of use increase from 7.164 cents per kWh to 8.185 cents, or 14.3%; and that the charge for additional

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[6] U.S. EIA, *Electricity Sales, Revenue, and Average Price – 2023 Utility Bundled Retail Sales - Residential* (Oct. 10, 2024, with data for 2023) ("EIA Data") at data table T6, https://www.eia.gov/electricity/sales_revenue_price/.

[7] *Id.* Calculated as (70,005780,000 kWh/5,147,906 customers)/12 months = 1,133 kWh/customer/month; $0.1501 x 1,133 kWh = $170.14 /customer/month.

[8] Cohen Direct, Ex. TCC-3 at 1.

[9] EIA Data, *supra* n. 6.

[10] MFR A-02 Test.

kWh be increased from 8.170 cents per kWh to 9.185 kWh, or 12.4%. This approach of smaller increases for higher uses makes the proposed rates economically regressive and promotes increased use of energy on the margin.

Taken together, FPL's base rate increase proposals would result in about a 13.6% increase in residential base rates.

Table KRR-2: FPL Proposals for 2026 Base Rate Increases

Usage Level	Current Base Rates	Proposed 2026 Base Rates	Increase per Month	% Base Rates Increase
250	$27.52	$31.38	$3.86	14.0%
500	$45.43	$51.85	$6.42	14.1%
750	$63.34	$72.31	$8.97	14.2%
1,000	$81.25	$92.77	$11.52	14.2%
1,250	$101.68	$115.73	$14.05	13.8%
1,500	$122.10	$138.70	$16.60	13.6%
1,750	$142.53	$161.66	$19.13	13.4%
2,000	$162.95	$184.62	$21.67	13.3%
2,250	$183.38	$207.58	$24.20	13.2%
2,500	$203.80	$230.55	$26.75	13.1%
2,750	$224.23	$253.51	$29.28	13.1%
3,000	$244.65	$276.47	$31.82	13.0%

Source: MFR A-02 Test

FPL proposed in this petition to further increase base rates in 2027, and the combined effect of the 2026 and 2027 increase is about a 22% increase in base rates.

Table KRR-3: FPL Proposals for 2026 & 2027 Base Rate Increases

Usage Level	Current Base Rates	Proposed 2026 & 2027 Base Rates	Increase per Month	% Base Rates Increase
250	$27.52	$33.75	$6.23	22.6%
500	$45.43	$55.77	$10.34	22.8%
750	$63.34	$77.80	$14.46	22.8%
1,000	$81.25	$99.82	$18.57	22.9%
1,250	$101.68	$124.35	$22.67	22.3%
1,500	$122.10	$148.87	$26.77	21.9%
1,750	$142.53	$173.40	$30.87	21.7%
2,000	$162.95	$197.92	$34.97	21.5%
2,250	$183.38	$222.45	$39.07	21.3%
2,500	$203.80	$246.97	$43.17	21.2%
2,750	$224.23	$271.50	$47.27	21.1%
3,000	$244.65	$296.02	$51.37	21.0%

Source: MFR A-02 2027 TY

Q. The MFR's submitted by FPL do not show such significant increases in estimated total bills in 2026 and 2027. Why is the data you present different?

A. FPL zeros out the Storm Charge in both 2026 and 2027, so total bills reflect small net increases. This is misleading. FPL's service territory will likely experience severe weather in 2025 as the effects of climate change increase the likelihood of major storms and hurricanes.[11] Damages from such weather will most likely trigger Storm Charges added to customer bills in 2026.[12]

Q. You are implying that current impacts on actual residential customer bills calculated from actual usage levels should be an important factor in evaluating the FPL's performance and the rates, programs, adjustments, and spending it is proposing. Why are current and actual bill impacts important?

A. Current and actual residential bill impacts are not the only factor for consideration in setting rates, to be sure, but they are critically important today and to the members and organizations on whose behalf I am testifying. Some of the reasons that these impacts are so important include:

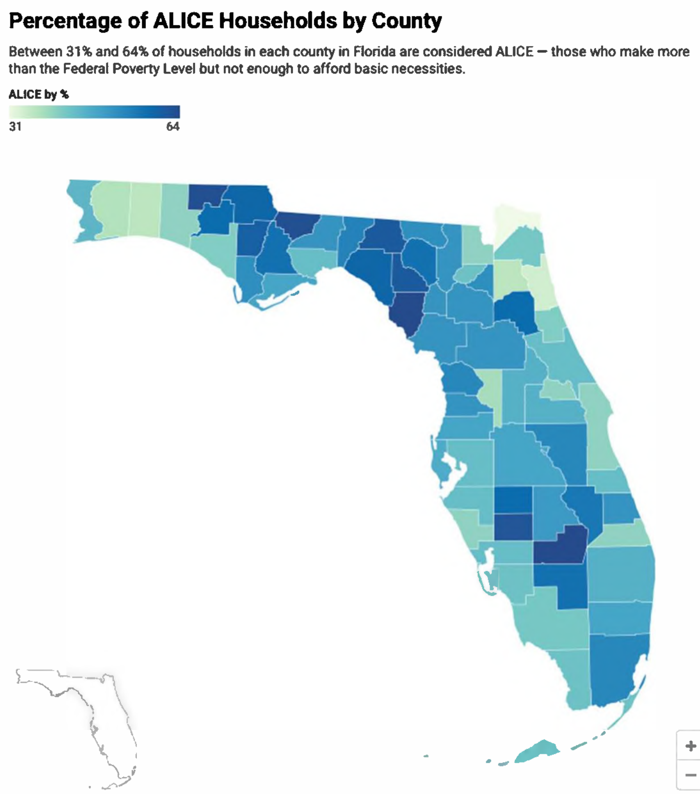
- Millions of Floridians live in poverty and in households where the average income is so low that they face a significant energy burden that will be made worse by the increases in bills proposed in this proceeding. As of 2022, about 1,125,129 households, or 12.8% of the total in Florida,

[11] Ryan Truchelut, *Hurricane Season 2025: Good News and Bad from the Florida Forecast* Tallahassee Democrat (May 27, 2025), https://www.tallahassee.com/story/news/hurricane/2025/05/27/hurricane-season-in-florida-2025-odds-more-as-tropics-wake-up/83796388007/ (predicting at 65% chance of an above-normal hurricane season in 2025).

[12] *See* Direct testimony of FPL witness Scott R. Bores ("Bores Direct"), Exs. SRB-4 & SRB-5.

were in poverty.[13]

- As of 2022, about 2,931,091 households, or 33.3% of the total in Florida, were characterized as "Asset Limited, Income Constrained, Employed" ("ALICE"). While many of these households have income levels above the federal poverty rate, they still struggle to make ends meet and face economic disaster from even one emergency event. The map below shows how ALICE rates vary by Florida county.[14]



- Poverty is worse in major counties served by FPL. In Miami-Dade County, 53% of households face financial hardship, followed by Broward County, at 48% of households, and Palm Beach County, at

[13] Julia Cooper, *Half the Households in Florida Struggle to Make Financial Ends Meet, Major Report Shows*, WLRN Public Media (Jul. 10, 2024), https://www.wlrn.org/government-politics/2024-07-10/florida-alice-united-way-report-affordability.
[14] *Id.*

47%.

- The way in which FPL proposes to implement the rate increases in this case imposes more burden on low users of electricity than on high electricity users. Low users of electricity in Florida are more likely to be low-income customers, members of minority races or ethnic groups, or elderly, so the impacts of the rate increases are felt most by those least able to bear the added burden.[15]
- The economic hardships facing ALICE households and households in poverty are worsened by FPL rates like its minimum bill, making it impossible to for low-income, low-use customers to reduce their bills below the minimum, whether through conservation or privation.

Q. Please summarize your recommendations based on your findings.

A. Based on my review of the evidence relating to the topics previously listed, I recommend that the Commission deny FPL's petition and direct it to refile after having addressed the problems cited in this testimony. On the specific issues, I offer the following recommendations to the Commission:

Return on Equity and Capital Structure

- The Commission should grant FPL an allowed return on equity of no more than 9.60%, centered in a 200-basis point range of 8.60% to 10.60%.
- The Commission should deny FPL's proposed minimum bill increase and order FPL to eliminate the minimum bill provision entirely.
- The Commission should allow the Company to adopt a capital structure

[15] Exhibit KRR-3, National Consumer Law Center, *Utility Rate Design: How Mandatory Monthly Customer Fees Cause Disproportionate Harm*, 2015.

with an equity ratio no higher than 50.52%, and a rate of return ("ROR") no higher than 6.07%.

- These changes alone, even accepting all of FPL's planned capital spending (which I recommend the Commission reject significant portions of), would mean FPL is already projected to overearn and that the rate increase should be rejected.
- Given that I recommend that the Commission reject the 2026 rate increase, I recommend that the Commission require FPL to refile a petition for a rate increase in 2026 if FPL still wishes to increase rates in 2027.

Capital Spending

- The Commission should not authorize any capital spending driven by FPL's stochastic loss of load probability analysis ("SLOLP"). The Commission should deny FPL's proposal to construct the 522 MW Northwest Florida battery project and the other battery projects in its rate plan proposal for the 2026-2029 timeframe and require a full cost-effectiveness analysis, including evaluation of all generation, storage, and demand-side alternatives.
- The Commission should deny FPL's proposal to implement the TAM.
- The Commission should deny FPL's proposal to apply storage-related ITCs in a single year following commissioning of battery facilities, and direct FPL to normalize the credits in order to adhere to the matching principle.

II. <u>FPL'S 12 CP 25% COST ALLOCATION METHOD FOR PRODUCTION COSTS SHOULD BE REJECTED AND REPLACED WITH A MODEL THAT ALLOCATES BASED ON ENERGY OR CAPACITY, BY GENERATION TYPE</u>

Q. What cost allocation model does FPL propose for allocation of production costs?

A. FPL's current rates are based on a 12 coincident peak ("CP") and 1/13th weighted average demand method ("12 CP and 1/13") for production costs and the results of the 2021 settlement agreement. FPL proposes moving to a 12 CP method that substitutes a 25% energy weighting for the 1/13th calculation currently in use ("12 CP and 25%").[16]

Q. What factors are considered when deciding which allocation method to use?

A. Although arguments and justifications about which cost allocation method to use are often couched in broad assertions about which method better reflects cost causation, the decision of how to slice the pie of total revenue requirements often devolves to a contest of regulatory political power played out in confidential settlement negotiations. Very large customers with the ability to fully participate in rate proceedings represented by expensive consultants often do better than residential consumer advocates with limited budgets. It is also true that because the number of residential customers and small business customers vastly exceeds the numbers of customers in other classes, assignment of revenue requirement increases to small customers can result in smaller per-unit or per-bill increases relative to other customer classes and a politically more attractive result.

[16] Direct testimony of FPL witness Tara DuBose ("DuBose Direct") at 22.

Additionally, under a somewhat perverse and certainly unjust theory of inverse elasticity, monopoly utilities often find convincing the argument that excess costs should be assigned to customers with the least opportunity to do anything but pay the charges.[17]

Q. What factors should inform the choice of allocation method?

A. The objective of the choice of allocation method is to reflect the character of the costs being allocated. The production costs allocator should reflect the character of the costs for various kinds of production and should result in an allocation that reflects how customers are using the production plant components of the system. Finally, the choice of allocation method should reflect the evolving character of the mix of production resources.

In FPL's case, the utility is increasingly focused on net system peak planning to address capacity needs, generally through batteries, and on increasing the amount of solar generation, which is an energy-producing generation resource that provides relatively little marginal capacity for the system net peak. This is to say that FPL's focus is on reflecting both the capacity and energy elements of the system, and the customers that use them, and has tried to find an allocation approach that strikes an appropriate balance.

Q. What method do you recommend that FPL be required to use to allocate production costs?

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[17] The Wikipedia entry related to the so-called "Ramsey Problem" explains this approach as follows: "The Ramsey problem, or Ramsey pricing, or Ramsey–Boiteux pricing, is a second-best policy problem concerning what prices a public monopoly should charge for the various products it sells in order to maximize social welfare (the sum of producer and consumer surplus) while earning enough revenue to cover its fixed costs. Under Ramsey pricing, the price markup over marginal cost is inverse to the price elasticity of demand and the price elasticity of supply: the more elastic the product's demand or supply, the smaller the markup." Wikipedia, *Ramsey Problem*, https://en.wikipedia.org/wiki/Ramsey_problem (last visited June 5, 2025).

A. I recommend that FPL and the Commission reorient their thinking toward a production plant allocation method that deals with the issues head on. That is, I recommend that FPL allocate production plant costs according to the primary function that types of generators perform. Nuclear and solar plants are primarily energy generators and are not highly dispatchable in a way that supports firm capacity needs on the margin. Gas plants and batteries provide firm capacity and are dispatchable. I acknowledge that combined cycle plants are also energy generators, but these are not the most economical choice for providing energy when compared to solar. In short, I recommend that FPL use a "12 CP and Energy/Capacity" allocation method that allocates the costs of all nuclear and solar plants to energy, and the costs of all gas plants and battery facilities to demand.

Q. Have you allocated costs using this methodology?

A. Yes. I've attached a modified version of FPL's cost of service study as Exhibit KRR-4, changing the rate of return, as I suggest below, and allocating the production costs as I've recommended above. This modified version is based on the attachment that FPL provided in response to FIPUG interrogatory number 11. FPL did note that there were some minor errors in that spreadsheet, but I understand that they are not significant. I attach this for information purposes, as this cost of study still includes projects that I recommend that the Commission reject, as discussed elsewhere in my testimony. It also includes FPL's current sales forecasts, which, as I note later, under-forecasts sales, leading to higher earnings for FPL and higher rates. I provide this evidence to demonstrate that the residential class is greatly overpaying its fair share of system costs—by hundreds of millions of dollars as compared to the other customer classes.

III. RETURN ON EQUITY AND CAPITAL STRUCTURE

Q. What amount does FPL propose it should receive as a return on equity in this proceeding, and what fraction of the capital structure does it propose that equity should comprise?

A. FPL, through witness James M. Coyne, proposes a retail regulatory ROE midpoint for FPL of 11.9% for the years 2026 through 2029, a rounded recommendation based on simple averages of modeling results and the addition of nine basis points for equity floatation costs.[18] FPL further recommends a capital structure comprised of 59.6% equity and 40.4% debt ("equity ratio").[19]

Q. How do the 11.9% ROE and 59.6% equity ratio requests square with experience across the U.S.?

A. FPL's proposals are materially out of step with authorized returns and equity ratios across the U.S. The Edison Electric Institute's ("EEI") Annual Financial Review for 2023[20] reports that in 2023, the average awarded ROE was 9.58%[21] and the equity ratio for U.S. investor-owned electric utilities was 41.6% equity to 58.4% debt.[22] S&P Global's subsidiary, Regulatory Research Associates ("RRA") reports that in recent decisions on major U.S. rate cases, the average awarded ROE was 9.68% for the first half of 2024, and was 9.60% for all of 2023, representing about 120 decided cases.[23] RRA reports that the average

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[18] Direct testimony of FPL witness James M. Coyne ("Coyne Direct") at 5.
[19] Coyne Direct at 61.
[20] EEI, *2023 Financial Review,* https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Finance-And-Tax/Financial_Review/FinancialReview_2023.pdf?la=en&hash=FB0D944B04D706A3ECA322DA98D5DF25CA3425BD [hereinafter "EEI Financial Review 2023"].
[21] *Id.* at 70.
[22] *Id.* at 60.
[23] Lisa Fontanella, Major Energy Rate Case Decisions, RRA (Jul. 29, 2024) at 3-6,

equity ratio for cases decided in 2023 was 51.15%.[24]

Q. How does FPL justify a request so out of step with utility industry conditions?

A. FPL witness Coyne presents results from estimating ROE with four models.[25] Mr. Coyne's analysis is like many that I have seen and is the product of two key factors: First, general arguments that high returns are necessary to ensure access to capital at reasonable costs, and second, the strong incentive to generate the highest ROE values possible. I offer no argument that Mr. Coyne's calculations did not produce the results they do, or that Mr. Coyne's selection of a proposed ROE is inconsistent with those modeling results. My testimony is that FPL's proposed ROE and equity ratio are out of step with industry norms and that there is substantial evidence that FPL's proposed ROE exceeds the actual cost of equity for FPL and its parent NextEra Energy. I further note that there is no evidence that FPL has faced any difficulty in accessing capital at reasonable costs.

Q. Is the problem with excessive authorized rates of return limited to FPL?

A. The problem of excessive authorized returns is unfortunately endemic among investor-owned utilities in the U.S., but FPL leads the pack. A recent study from the American Economic Liberties Project documents these and other problems with awarded ROEs for investor-owned utilities in detail, hereinafter the

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https://pscdocs.utah.gov/electric/24docs/2403504/336109DPUExhbt3.14MjrEnrgyRtCsDcsns10-17-2024.pdf. RRA defines a "major" case as on in which the "utility's request would result in a rate change of at least $5 million or in which the commission approves a rate change of at least $3 million."

[24] *Id.* at 7.

[25] Coyne Direct at 32-33.

"ROR=COC" report, for "Rate of Return Equals Cost of Capital."[26] A very accessible primer published by RMI also recognizes these problems and points out that on average, utility profits now reflect nearly 17% of the average customer bill, hereinafter "RMI ROE Primer."[27] The Pearl Street Station Finance Lab observed that utility ROEs above those for similarly credit-rated industries could have cost American utility customers up to $214 billion during the decade 2010-20 and $34 billion in 2020 alone—with such overcharges by FPL topping the list.[28]

Q. You stated that you do not take issue with the fact that FPL's modeling of a proposed ROE produced the results that it did. Does that mean that you approve of the models themselves?

A. There are recognized problems with excessive utility rates of return allowed by utility commissions as well as the modeling that utilities provide to support their ROE requests. In general, these models produce recommended ROEs that greatly exceed the cost of equity, which should be where the ROE is set. As noted in the ROR=COC report:

> [U]tility rate of return experts frequently employ four different models to estimate the cost of equity. Two of them — the risk premium model and expected earnings analysis — are used only in utility regulatory proceedings and

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[26] Mark Ellis, Rate of Return Equals Cost of Capital: A Simple, Fair Formula to Stop Investor-Owned Utilities from Overcharging the Public, American Economic Liberties Project (Jan. 2025), https://www.economicliberties.us/wp-content/uploads/2025/01/20250102-aelp-ror-v5.pdf [hereinafter "ROR = COC"].

[27] Joe Daniel, Ryan Foelske, & Steve Kihm, Rebalancing "Return on Equity" to Accelerate an Affordable Clean Energy Future, RMI (Feb. 21, 2025), https://rmi.org/rebalancing-return-on-equity-to-accelerate-an-affordable-clean-energy-future/ [hereinafter "RMI ROE Primer"].

[28] Albert Lin, *Electricity Bills Too High? Then, Get the ROE in Line,* Pearl Street Station Finance Lab, https://www.ourfinancelab.com/post/electricity-bills-too-high-then-get-the-roe-in-line (last visited June 9, 2024).

nowhere else in finance. This is because they do not even purport to estimate the cost of equity but merely calculate return on equity based on either historical regulatory-awarded ROEs (the risk premium model) or forecasts of future ROEs which, in turn, are based on recently awarded ROEs (the expected earnings analysis). Promisingly, in 2022, the FERC recognized these models' circularity and prohibited their use, observing that they "def[y] general financial logic." Nonetheless, both utility and non-utility experts continue to use them in state proceedings, mostly unchallenged.

The other two models commonly used in utility regulatory proceedings, the capital asset pricing model (CAPM) and discounted cash flow model (DCF), are all used by other finance practitioners and academics. Nonetheless, utility ROR experts routinely implement the DCF and CAPM with unrealistic assumptions to arrive at results comparable to those produced by the conceptually flawed ROE-based models. Examples of faulty implementation include growth projections for corporate profits, which currently account for less than 10% of US GDP, overtaking GDP in its entirety within a decade or two; and relying on input assumptions from providers with multi-decade track records of systematic upward bias.[29]

I therefore recommend that the Commission not rely on the modeling results submitted by FPL's witness Coyne.

Q. Does FPL's current allowed ROE accurately reflect its *cost* of equity ("COE")?

A. If FPL's ROE were numerically the same as its COE, its stock should trade at its

[29] ROR=COC, *supra* n. 26, at 11 (citations omitted).

book value, which reflects historical investment used to inform revenue requirement calculations.[30] Comparing the market value or price of a stock to its book value indicates whether the ROE is set at the COE. FPL is owned by NextEra Energy. NextEra Energy has a current price to book ratio of 2.98,[31] and Eqvista reports that as of January 2025, electric utility had a price to book ratio of 1.67.[32] FPL's ROE is higher than its COE, as evidenced by the market's willingness to pay a premium over its book value.

Q. Can you estimate what return investors require from FPL?

A. Using a discounted cash flow calculation can inform whether FPL's current authorized of equity is lower than its cost of equity. I used the formula below, provided in the RMI ROE Primer to estimate FPL's cost of equity.

$$COE = \frac{ROE}{\left(\frac{P}{B}\right)} + \left[1 - \frac{1}{\left(\frac{P}{B}\right)}\right](b \times ROE)$$

In this formula:

COE = cost of equity	ROE = return on equity
P|B = price to book ratio	b = earnings retention ratio

In my estimation, I used FPL's current allowed midpoint ROE of 10.8%, the average utility price-to-book ratio of 1.67, and estimated the earnings retention ratio by subtracting the dividend payout ratio of 63.7% reported by EEI

30 RMI ROE Primer, *supra* n. 27.

31 Yahoo!Finance, NextEra Energy, Inc. (data as of close of markets, Jun. 6, 2025), https://finance.yahoo.com/quote/NEE/key-statistics/.

32 Sarath, *Price-to-Book Ratio by Industry (2025),* Eqvista (Jan. 29, 2025), https://eqvista.com/price-to-book-ratio-by-industry/.

for electric utilities[33] from 100%, to yield a 36.30% earnings retention ratio.

My calculations estimate that FPL's COE is 8.04%, substantially lower than its current allowed ROE of 10.8%. Even at the top of its current allowed ROE band of 11.8%, the COE for FPL would be 8.78%.

Q. Are you recommending an allowed ROE based on the 8.04% level?

A. My calculation was based on publicly available data about the electric industry as a whole. I offer this calculation to make two points in this testimony. First, FPL's requested allowed ROE of 11.9% is extreme and likely to be 300 or more basis points higher than its cost of capital. Second, the Commission should not have confidence in FPL's analysis in setting FPL's allowed ROE.

Q. Witness Coyne also offered an analysis of business risk faced by FPL. Do you agree with his testimony on this issue?

A. Witness Coyne offers testimony that FPL faces many business risks that support the high proposed ROE and equity ratio under the basic assertion that investors will not buy FPL/NextEra stock or lend FPL money unless they realize outsized profits. FPL does not propose separate and additional adders to the proposed ROE and equity ratio based on these asserted business risks,[34] which strongly suggested that the modeled results themselves give outsized weight to asserted business risk.

Q. How does FPL portray its business risk profile?

A. First, witness Coyne points to FPL's excessive capital investment program as creating a risk, noting that the Company's capital expenditures between 2025 and 2028 will average $9.75 billion each year, and that these expenditures alone

[33] EEI Financial Review 2023, *supra* n. 20 at 9.
[34] Coyne Direct at 44-45.

equal about 57% of FPL's total net utility plant as of the end of 2023.[35] FPL's spending is outsized even in comparison to the proxy companies that witness Coyne selected for his analysis.[36] He concludes this argument by asserting that substantial expenditure programs heighten the risk of under recovery or delayed recovery of investments and put downward pressure on key credit metrics.

Q. Do you agree with these arguments?

A. FPL's arguments do not support higher ROE or equity ratio. FPL has in place and is proposing additional mechanisms that would practically guarantee full and timely recovery of all revenue requirements. It can argue for ROE to compensate for revenue risk, or it can argue for rate and accounting mechanisms to do the same, but it is not reasonable that it be allowed both. If this business risk is real, FPL should decrease its capital spending plans *and* its requested ROE, not increase both. As I will explain later, a substantial amount of FPL's proposed spending on battery facilities is derived from a dubious SLOLP analysis.

Q. What other risk arguments does FPL make, and are they persuasive?

A. Mr. Coyne finds FPL's ownership of nuclear generating assets is a relative risk increaser, even though two-thirds of the companies in his proxy group have nuclear assets in their generation mix. Mr. Coyne finds FPL's exposure to severe weather another risk increaser. The fact, however, is that FPL benefits from a legislated cost recovery account that ensures timely and full recovery of prudently incurred storm recovery costs. With the storm hardening mandate and the storm recovery cost mechanism, even though severe weather is likely for Florida, FPL's exposure to financial threats as a result is largely in FPL's hands.

[35] *Id.* at 45.
[36] *Id.* at 47-48.

As for regulatory risk, Mr. Coyne finds that several of the companies in his proxy group have some of the cost recovery and earnings protection mechanisms enjoyed by FPL—but he does not indicate that any have all that FPL does. All this argues for a reduction in the allowed ROE. Mr. Coyne tries to argue that FPL is a riskier investment because it does not enjoy a revenue decoupling mechanism. In my opinion, a revenue decoupling mechanism with active regulatory oversight would be an improvement over the accounting manipulation tools that FPL appears to favor and would certainly provide much needed transparency into FPL's financial activities, but to imply that the lack of a decoupling mechanism adds risk that offsets the other risk-reducers FPL enjoys is to ignore reality. A fair characterization of FPL's tax and investment tax credit proposals is that it is seeking to implement a decoupling mechanism and a formula rate plan, but without the usual attendant regulatory oversight. If FPL gets its way, there is little or no real risk remaining.

Mr. Coyne also finds that the Company is choosing to take on additional risk with its proposal for a multi-year rate plan, due to the risk of inflation resulting from monetary and fiscal policy in the current federal administration. Again, a realistic assessment is that with all the mechanisms FPL has in place and proposes, the multi-year rate plan does not create a significant negative financial risk for the Company or its shareholder. In all, Mr. Coyne fails to make a case for a higher ROE for the Company based on risk and wisely does not try. However, the weakness of FPL's business risk assertions does countenance a reduction in the proposed ROE and equity ratio.

Q. Witness Coyne inflates the FPL proposal by nine basis points to provide profits to pay for the costs of issuing equity. Is this proposal reasonable?

A. No. While in my experience it is common for regulators to approve recovery of flotation costs, the inflation of the ROE to pay those costs is not a reasonable approach because it will not encourage efficient behavior by FPL. The Commission already generally approves a band for earned ROE that can exceed allowed ROE by 100 basis points. FPL should pay for flotation costs out of this potential uplift in earnings, not be paid on top of it.

Q. What ROE do you recommend that the Commission approve for FPL?

A. Because FPL faces substantially lower business risk than assessed by FPL witness Coyne; because NextEra's stock trades at a price to book ratio of 2.98 and electric utility price to book ratios are in the range of 1.67, indicating that required return is substantially lower than FPL's current allowed ROE of a midpoint 10.8%; and because a straightforward calculation of the cost of equity under a DCF model that focuses on observable market data reveals a cost of equity well below 10%; I recommend an allowed ROE at the weighted average of awarded ROEs in the period of 2023 and the first half of 2024, as reported by RRA, or 9.6%, with a range of 8.6% to 10.6%. I recommend an equity ratio of 50.52% equity to 49.48% debt, equal to the mean value for equity ratios in 2023 for Mr. Coyne's capital structure proxy group.[37]

Q. What are the impacts of the adjustments to ROE and equity ratio you would propose in terms of revenue requirement?

A. Because of the large rate base in place and the significant proposals for rate base growth, the impact of a lower ROE and equity ratio would be significant and positive for residential customers. My high-level calculation is that the revenue

[37] Coyne Direct, Ex. JMC-11 at 1.

requirement in total is reduced by about $5,000,000 for each basis point reduction in the ROE. The total impact of my ROE and equity ratio proposals is a reduction in the revenue requirement for 2026 from $1.544 billion to -$28.16 million, for a reduction in costs to customers of $1.573 billion. This means that adjustments to the ROE and equity ratio to make them more just and reasonable can significantly reduce the rate impact of proposed spending and investment by the Company. Moreover, when the unreasonable spending proposals by FPL are eliminated and ROE and equity ratio are corrected, the Commission could order a decrease in customer rates for FPL customers.

IV. CAPITAL SPENDING

Q. What kinds of significant capital spending does the Company propose?

A. FPL witness Andrew Whitley presented testimony relating to planning and resource additions.[38] The Company proposes to build several new solar plants and battery storage facilities during the years 2025 through 2034.

[38] Direct testimony of FPL witness Andrew W. Whitley ("Whitley Direct")

Figure KRR-1: FPL Resource Plan Comparison [39]

Resource Plan Comparison

	(1)	(2)	(3)
Meets Standard 20% Reserve Margin:	Yes	Yes	Yes
Meets 0.1 Days Per Year LOLP Using Traditional Calculation:	Yes	Yes	Yes
Meets 0.1 Days Per Year LOLP Using Stochastic Calculation:	Unevaluated*	Yes	No

Common to all Plans Retirements / Additions	Year	Without Proposed 2026 and 2027 Solar And Battery Additions	Reserve Margin (%)	FPL Resource Plan with Rate Case Additions	Reserve Margin (%)	FPL Resource Plan - No Additions to Meet LOLP	Reserve Margin (%)
Pea Ridge (12 MW)	2025	894 MW Solar	22.4	894 MW Solar	22.4	894 MW Solar	22.4
---	2026	522 MW Battery NWFL	22.1	522 MW Battery NWFL 894 MW Solar 1,419.5 MW Battery	24.1	522 MW Battery NWFL 894 MW Solar	23.1
Broward South (4 MW)	2027	---	21.1	1,192 MW Solar 819.5 MW Battery	27.2	1,192 MW Solar	22.3
Lansing Smith A (32 MW)	2028	1 x 2x0 CT (475 MW)	21.0	1,490 MW Solar 596 MW Battery	26.6	2,235 MW Solar	20.9
---	2029	1 x 2x0 CT (475 MW)	21.2	1,788 MW Solar 596 MW Battery	26.3	2,235 MW Solar 224 MW Battery	20.5
GCEC 4 (75 MW), GCEC 5 (75 MW), Perdido 1&2 (3 MW)	2030	1 x 2x0 CT (475 MW)	21.1	2,235 MW Solar 596 MW Battery	25.8	2,235 MW Solar 522 MW Battery	20.6
---	2031	1 x 2x0 CT (475 MW)	21.5	2,235 MW Solar 596 MW Battery	25.7	2,235 MW Solar 373 MW Battery	20.6
---	2032	1 x 2x0 CT (475 MW)	20.9	2,235 MW Solar 596 MW Battery	24.5	2,235 MW Solar 969 MW Battery	20.6
---	2033	1 x 2x0 CT (475 MW)	20.8	2,235 MW Solar 596 MW Battery	23.9	2,235 MW Solar 969 MW Battery	21.0
---	2034	1 x 2x0 CT (475 MW)	20.5	2,235 MW Solar 596 MW Battery	23.0	2,235 MW Solar 2,533 MW Battery	22.9

	(1)	(2)	(3)
CPVRR Costs =	$108,841	$99,322	$98,776
CPVRR Costs Difference from the Without Proposed Solar and Battery Additions Plan =	–	($9,520)	($10,065)
CPVRR Costs Difference from the FPL Plan with Rate Case Additions =			($545)

Notes:
CPVRR costs are in million $ and are discounted at 8.15% (FPL's most recent WACC) for the years 2025 thru 2071
Negative values indicate CPVRR savings to customers
Analysis assumes new CT capacity is available in 2028 to put plans on equal footing; realistically new CT installations would not be available until late 2029 or early 2030 at the earliest
Plans that do not add resources based on stochastic modeling have multiple years of reliabilty risk to customers

* FPL has not conducted a stochastic LOLP evaluation of this plan

[39] FPL response to Staff 3rd Int No. 44 Corrected Supp, Att. 1.

As shown in Figure KRR-1, FPL's proposed resource plan proposes huge new solar and battery investments in the years 2026 and 2027, and beyond. FPL estimates that its resource plan has a cumulative present value of revenue requirements that is $545 million more than a resource plan developed without the use of FPL's new SLOLP analysis.

Q. Please describe FPL's decision to use SLOLP analysis.

A. FPL selected Energy and Environmental Economics, Inc. ("E3") to provide the SLOLP analysis. The selection process is important to understand. FPL had E3 under contract to perform unrelated work, and engaged them to perform the SLOLP analysis in late 2024.[40] By the time that E3 had been engaged for the SLOLP process, FPL had already decided to significantly increase its spending on batteries in its 2025 plan.[41] As such, it appears that E3 was retained to provide support, through the use of SLOLP, for an investment decision FPL had already made. FPL had not previously used the SLOLP methods in its planning, and to my understanding, the Commission has not made any significant resource adequacy determinations based on the SLOLP methodology.

Q. Briefly summarize resource adequacy analysis with SLOLP and how it compares to conventional analytic approaches.

A. First, it is important that FPL already performs conventional loss of load probability analysis ("LOLP"). Second, FPL already uses a planning reserve margin metric of 20% to evaluate alternative resource plans, a generation only reserve margin metric of 10%, *and* conventional LOLP analysis.[42] FPL explains

[40] FPL response to Staff 3rd POD No. 21 (E3 Proposal to conduct SLOLP analysis dated October 14, 2024).
[41] *See* FPL response to FEL 1st RFA No. 25 (E3 study "helped inform and confirm FPL's resource plan").
[42] Whitley Direct at 10-11.

its decision to engage E3 to perform the SLOLP as growing out of the observation that increasing reliance on solar generation was resulting in system peaks occurring later in the day.[43]

Like conventional loss of load probability analysis, SLOLP seeks to identify the likelihood that a particular resource mix will result in a probability of outages that exceed a targeted level of reliability.[44] The typical standard, and the one used by FPL, targets loss of load probability no greater than 1 day in 10 years, or .1 day in one year. Also like conventional LOLP, SLOLP is grounded on a range of assumptions about the operating performance of various energy resources and the likelihood or necessity that those resources will not perform as expected.[45]

Unlike conventional LOLP analysis, SLOLP relies on running hundreds or even thousands of simulations to identify the likelihood that simultaneous resource failures or reductions in performance will create outage hours that exceed the planning goal of .1 day in a year. These simulations are supposed to involve randomly selecting generation or battery units for outages to reach a conclusion about how many megawatts of capacity are required to meet peak demand and have confidence that the LOLP target will not be exceeded.

Q. What is the practical result of the use of SLOLP analysis to evaluate resource adequacy?

A. The practical result is that rather than exercising judgment about the likelihood of simultaneous outages that would result in excessive loss of load, the SLOLP

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[43] *Id.* at 12.
[44] *See* Whitley Direct, Ex. AWW-1.
[45] Whitley Direct at 12-14.

analysis can develop a vastly larger portfolio of outage scenarios and thus creates support for an argument that more resources are required to address even unlikely contingencies.

Q. Can you provide an example?

A. In reviewing data about outage scenarios generated by the SLOLP analysis tool, one can see outage events randomly generated by the tool in which several generating facilities were simultaneously offline.[46] In the SLOLP results, on one particular modeled day, presumed to be September 29 in the modeled year, several facilities hypothetically experience forced outages, and when combined with scheduled maintenance outages, created conditions that exceed the .1-day LOLP goal. Each of the facilities have already been characterized with a confidential forced outage factor—the percentage likelihood of an unscheduled outage.[47] Simple math—multiplying the individual outage factors for each plant experiencing a forced outage—reveals the cumulative probability that the LOLP scenario will occur with these multiple outages occurring simultaneously.

This cumulative probability of this LOLP scenario is 0.00000000004%. It is not surprising that a sophisticated and powerful model could generate such a scenario. But it is unreasonable to require customers to pay billions of dollars to ensure that the FPL system has so much excess capacity that such remote events are confidently avoided. Moreover, FPL has provided evidence in this proceeding that its generation fleet is meeting high standards for availability and

[46] FPL response to FIPUG 1st POD No. 5, spreadsheets 'all_unserved_energy_and_reserve_hours' (FPL's response includes a series of E3 folders representing different years and model runs which each contain a file with this title).

[47] The outage factors are contained in FPL response to OPC 1st PODs No. 15, FPL Fossil OH IRP 2025 to 2034 Rev 10-8-2024-CONFIDENTIAL.

performance.[48]

Q. Are there other issues that appear in the SLOLP documentation?

A. It was my understanding that the SLOLP process was intended to generate and analyze a range of random scenarios to identify resource adequacy risks. A review of the data provided about the scenarios does not support this assumption. For example, certain generation units that contribute to calculated LOLPs that are below the target .1 day/year level always have issues of forced outages or significant reductions in output or are always out or reduced on specific days.[49]

Further, the E3 analysis uses assumptions about solar output that are lower than FPL has experienced.[50] E3 solar production values have additional issues, like being higher than those experienced by FPL on December mornings, including production before the sun rises.[51]

Q. What other concerns do you have with the SLOLP analysis?

A. The modeling performed for FPL made several questionable assumptions about de-rating the capacity of rooftop solar generation[52] and reducing the contribution capability of demand response,[53] as well as the extremely improbable forced outage events. The SLOLP analysis also assumes FPL has zero ability to import power from any other electric utility, when, in fact, FPL can import some power

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[48] *See* direct testimony of FPL witness Thomas Broad at 7-9 (fossil units); direct testimony of FPL witness Dan DeBoer at 7-15 (nuclear units).
[49] FPL response to FIPUG 1st POD No. 5.
[50] FPL response to OPC 1st POD No. 15, Whitley, Input to E3, excel workbooks "FPL Historical Load and Solar."
[51] *See* FPL response to FIPUG 1st POD No. 5, spreadsheets "all_unserved_energy_and_reserve_hours" (showing significant solar production at 7am on morning of December 25th when sun does not rise in the very easternmost portion of Florida until after 7:05am).
[52] FPL response to OPC 1st POD No. 15, Whitley workpapers, "2025-02-21 RA Study Workpapers.xlsx".
[53] Whitley Direct at 39.

from other utilities, and has done so, if its neighbors have any excess capacity.[54] In addition, the SLOLP tool is proprietary to E3 and it appears it cannot be used by stakeholders outside of a licensing or contractual arrangement.[55] It is also not clear what value is added by spending customer dollars on SLOLP modeling when the 20% planning reserve margin has served to ensure that FPL continues to meet or exceed system reliability objectives.[56]

Q. Do you conclude that SLOLP should not be used to support resource adequacy analysis?

A. Given FPL's lack of experience with the tool, the late and rushed way in which the SLOLP analysis was employed in relation to this petition, and the several concerns that I have raised, my conclusion is that the SLOLP analysis is not suitable as a reliability-related foundation for the massive incremental battery investments FPL is proposing.

Q. What do you recommend that the Commission do?

A. The Commission should reject FPL's proposal to build the additional battery resources, in 2025 and beyond, that FPL has added in this proceeding and ostensibly validated by the SLOLP analysis. FPL should bear the burden of proving that this new analysis approach adds value and demonstrably reduces operational risk for FPL.

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[54] A representative for E3 suggested during deposition that in weather-driven loss of load events, the same weather would impair neighboring utilities from exporting energy to FPL. May 29, 2025 Deposition of Arne Olson. To the extent that E3 modeled loss of load events primarily caused by staggeringly improbable swaths of FPL's thermal units facing simultaneous forced outages, E3 has provided no basis for assuming neighboring utilities would concurrently experience such cataclysmic failures of their own thermal fleets as to be unavailable to assist.

[55] Whitley Deposition at 46-47.

[56] *See, e.g.,* FPL response to FEL's 9th POD No. 71, "January 2025 – Winter Weather Event" at 8, 10 (maintaining ability to serve all load despite all-time peak for NW Florida, GCEC Unit 7 being out of service, and part of GCEC Unit 8 being off-line for 2.5 hours due to snow in the air intake).

V. FPL'S INADEQUATE JUSTIFICATION FOR THE 522 MW NORTHWEST FLORIDA ("NWFL") BATTTERY STORAGE PROJECT

Q. Please describe FPL's proposal to rate base 522 MW of new battery storage, called NWFL Battery Storage.

A. FPL appears to have sought approval from its board of directors in or around May 2023 for about 520 MW of new battery storage facilities in the northwest panhandle of Florida,[57] consisting of seven 74.5 MW 3-hour duration facilities co-located at solar generation sites.[58] These facilities appear in the resource plan documents submitted in this proceeding as "522 MW Battery NWFL."[59]

Q. What was the justification for the NWFL battery project?

A. According to the brief presented FPL's board of directors, the NWFL battery project was rushed into construction to address winter capacity requirements that could arise if the Florida panhandle experienced another major winter storm like the one called Winter Storm Elliott that occurred on Dec. 24, 2022.[60] FPL's recommendation was to have the NWFL battery project in place by December 2025 as well as power purchase agreements ("PPA") for interim needs until the North Florida Resiliency Connection transmission line is more available, which is expected for January 2027.

Q. Has FPL experienced a reserve deficiency in the panhandle in recent years?

A. I am not aware that FPL has experienced reliability issues associated with reserve deficiencies of significant magnitude. It is my understanding that PPAs have

[57] CONFIDENTIAL Company response to OPC 1st POD No. 43, Development (no confidential highlighted material is cited here or disclosed in the text above).
[58] FPL response to OPC 1st POD No. 15.
[59] *See, e.g.,* FPL response to Staff 3rd INT No. 44 Corrected Supplemental, Att. 1.
[60] CONFIDENTIAL Company response to OPC 1st POD No. 43, Development. (no confidential highlighted material is cited here or disclosed in the text above).

addressed the issue.

Q. Is a 522 MW battery project a prudent course of action to address capacity shortfalls that are expected to be alleviated in 2027, when the North Florida Resiliency Connection is expected to be more available?

A. A utility-scale battery project of 522 MW is a 20-year investment and is not an interim solution. PPAs appear to be meeting the interim need for capacity. I have found no evidence of an analysis of the cumulative present value of revenue requirements for the NWFL battery project economic value, nor of a formal reliability assessment that establishes reliability need conducted prior to FPL adding the NWFL Battery project to its resource plan. Moreover, in its own analysis following the 2025 winter snowstorm that hit the panhandle, FPL found that "New 4-hour batteries provide minimal support during the winter events where load is elevated for 14+ hours (hour ending 17 to hour ending 7)."[61] Three-hour batteries, of course, provide even less support than four-hour batteries. My conclusion is that FPL has not established the prudence of the NWFL battery project.

Q. What should the Commission do?

A. The Commission should direct FPL to prove that the NWFL battery project is prudent and that it will result in just and reasonable rates for FPL customers. FPL should be directed not to begin recovery until thorough review of the project is completed and the project is approved. Stakeholder and representatives of customer interests should be granted the right to intervene and participate in the review of the NWFL battery project.

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[61] FPL response to FEL's 9th POD No. 71, "Lessons Learned Enzo."

VI. FPL'S PROPOSAL FOR A TAX ADJUSTMENT MECHANISM

Q. What is FPL's TAM proposal?

A. FPL's proposed TAM is described by witness Laney.[62] FPL typically normalizes deferred tax liabilities over the lives of the related assets. As these deferred tax liabilities reverse, they reduce deferred tax expense. FPL's TAM is a proposal to accelerate this reversal period and to accelerate the recording of deferred tax expense to provide benefits that partially offset increased revenue requirements in the last two years of FPL's proposed four-year rate plan, 2028 and 2029. FPL proposes an almost $2 billion fund of unprotected deferred tax liabilities that it can draw on a rate that maintains its earnings even as it continues to increase spending and investment. FPL asserts that this is a benefit to customers because when FPL is maximizing its profits, it has less reason to seek rate increases from the Commission.[63]

Q. If the benefit of reductions in deferred tax expenses are used to offset increasing revenue requirements in 2028 and 2029, what happens to the deferred taxes?

A. The deferred taxes are amortized as a regulatory assert over the average remaining life of the underlying assets.[64]

Q. What are your concerns with the TAM?

A. The TAM intentionally deviates from normalization of deferred tax expense to support about $2 billion in additional increases in revenue requirement for FPL. The deferred taxes will be paid by customers for an additional 19 years, without

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[62] Laney Direct at 47-53.
[63] *Id.* at 46.
[64] *Id.* at 48-49.

the benefit of any reduction in deferred tax expense, because that was accelerated into the four-year rate plan. This raises two major issues of concern. First, it harvests a thirty-year stream of deferred tax expense reductions to enable more spending by FPL, and second, it creates a violation of the matching principle in rate making. Customers in the years 2028 and 2029 get the deferred tax expense reductions while customers in the years 2029 through 2048 pay the deferred taxes.

Q. Does FPL propose any limits on its discretion in utilizing the TAM?

A. There are only minimal constraints. First, FPL cannot use the TAM to realize an ROE outside the band approved by the Commission. Second, no more than $1.717 billion can be recorded as deferred operating income tax liability.[65] Other than those conditions, FPL proposes complete discretion over the use of the TAM.[66]

Q. How should the Commission act on FPL's TAM proposal?

A. The Commission should deny the proposal to implement the TAM. FPL's proposal creates significant temporal inequity in the costs and benefits of nearly $2 billion in deferred tax liabilities. The Commission should direct FPL to normalize the reductions in deferred tax expense for the related accounts.

VII. FPL's PROPOSAL TO OPT OUT OF NORMALIZATION OF ITC BENEFITS FOR ALL BATTERY STORAGE FACILITIES ADDED DURING THE 2025-2029 PERIOD

[65] *Id.* at 52. *See also* Errata Sheet of Ina Laney, filed April 29, 2025 (revising $2 billion TAM amount to $1.717 billion).
[66] Laney Direct at 52.

Q. What does FPL propose with investment tax credits that would be generated by investment in battery storage facilities?

A. In the past, FPL has fully normalized ITCs and spread the tax benefits over the book life of the underlying asset.[67] The federal Inflation Reduction Act allows owners to opt out of this normalization and take the full ITC benefits in the year after the facility begins operating. The effect is a significant reduction in revenue requirements in that first year after operations.[68]

Q. What does FPL propose to do with the tax credits it receives from the storage facility investments?

A. FPL assumes in its 2026 and 2027 tax years that it will use credits up to the allowed level of 75% of its standalone federal income tax liability, meaning it will be reimbursed for the full value of these credits.[69] FPL asserts that carrying excess tax credits forward would create a deferred tax asset that has an upward impact on revenue requirements. As a result, FPL plans to sell unused excess tax credits at an 8% discount. FPL asserts that selling the tax credits is more beneficial to customers than creating a tax credit carryforward without such sale.[70]

Q. What happens in the year after ITCs are recognized and reduce revenue requirements?

A. Because ITC benefits will have been fully consumed in the year after the facility enters service, the revenue requirement will increase, and the costs recovered through base rates and the SoBRA (for battery projects in 2028-2029) will be

[67] *Id.* at 22.
[68] *Id.* at 22-23.
[69] *Id.* at 23.
[70] *Id.* at 25.

raised.[71]

Q. What are your concerns relating to FPL's proposal to immediately take all the ITCs resulting from its construction of battery storage facilities?

A. As with its TAM proposal, FPL's ITC proposal raises serious concerns about the matching of costs and benefits to customers for the battery storage facilities. And consistent with its focus in this entire proceeding, FPL seems obsessively focused on growing rate base, without regard to the best long-term interests of its customers. It is true that the ITCs from the storage projects will dampen the initial impact of FPL resource acquisition binging, but the effect is only temporary, and the offsetting negative rate impacts will last for decades. And FPL appears comfortable further denying its customers 8% of the value of the ITCs due to a sales price discount. FPL's calculations suggesting greater value in immediate liquidation of the ITCs can only be explained by its reliance on a discount rate of more than 8%. Residential customers don't have the same high discount rate.

Q. Is there any way that FPL's ITC liquidation proposal can work for its customers?

A. There is no practical way that FPL's approach works for customers over the life of the storage asset. In return for one year's worth of revenue requirement benefits, customers will see 19 years of facility investment costs that are not mitigated by normalized ITC benefits. Like a Ponzi scheme, it could work if FPL kept increasing its portfolio of ITC-enabled storage facilities endlessly. But like a Ponzi scheme, it is unlikely to work for very long. Every year that FPL

[71] *Id.* at 53-54.

adds to the stock of battery facilities with the ITC cashed out in the first year after operations begin, it increases the amount of costs that are separated from the ITC benefit. The pancaking of such revenue requirement increases will soon become unbearable for customers.

Q. How do you recommend that the Commission respond to FPL's proposal to immediately take the ITC's generated by its storage facility investments?

A. The Commission should deny FPL's proposal to take all the storage-related ITCs in the first year. The Commission should order FPL to normalize the ITCs over the life of the underlying storage asset.

VIII. FPL'S MINIMUM BILL FOR RESIDENTIAL CUSTOMERS AND SMALL COMMERCIAL CUSTOMERS IS UNJUST AND UNREASONABLE

Q. What is FPL's minimum bill provision?

A. FPL's minimum bill applies to rate RS-1 and GS-1 customers. It operates to charge customers a certain minimum amount on their monthly bill regardless of whether their fixed customer charge and volumetric energy charges are lower than the minimum bill amount. For example, if a customer has base rate charges of $15, the customer must pay $25. If the customer has base rate charges of $24.99, the customer must pay $25.

Q. What does FPL propose for its minimum bill in its Petition?

A. FPL seeks approval to increase its minimum bill to $30, a 20% increase.[72]

Q. How does FPL calculate its minimum bill proposal?

A. FPL divides the total of customer and demand related base revenue requirements

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[72] Cohen Direct at 19-20.

for the 2027 projected test year by the number of bills it issues in a year. For residential customers, the result is $32.39, and for small commercial customers, the result is $37.38.[73] From this, FPL proposes a $30 minimum bill.

Q. How many customers does the minimum bill impact?

A. According to FPL, approximately 370,000 residential customers, or 6.8% of the total of residential customers, and 110,000 small commercial customers, or 19.6%, are expected to have a base bill less than $30 per month.

Q. What is the consequence of the minimum bill?

A. Customers affected by the minimum bill are required to pay for a service they did not use, and for costs they did not cause, to further improve the revenue stability for one of the most profitable electric utilities in the country. The concept of paying for a utility service they did not use is impossible to understand for customers buying under tariffed rates. The minimum bill treats demand-related distribution charges as if they were customer costs, even though demand-related costs vary with the amount of usage and are not based on customer count. The minimum bill weakens the economics of energy efficiency and is an inefficient way for the utility to recover demand-related costs, encouraging the utility to gold plate its distribution spending because of the certainty of recovery—the minimum bill enables, rather than discourages, the extraction of monopoly rents. The charge sends a message to customers telling them not to bother saving energy or use electric service efficiently, because they can't escape the minimum bill. The minimum bill is thus a "take or pay" charge that violates the premises of cost-of-service regulation. The minimum bill is economically regressive,

[73] MFR No. E-14.

having its worst impacts on very poor customers, retirees on fixed incomes, and students and the elderly living in small apartments. The minimum bill forces low-use customers to subsidize high use customers—it is reverse Robin Hood. In sum the minimum bill violates several core principles of sound utility rate making.

Q. How does FPL defend its minimum bill, and is that argument sound?

A. FPL relies on false and unsupported statements about economics and rate making.[74] FPL witness Cohen essentially argues for rate making by alliteration—that if a cost is labeled as "fixed" for accounting purposes, it is properly recovered with a "fixed" charge. There is no economic treatise, study, or evidence to support the idea that economic efficiency and fairness are improved when rate design mimics cost structure. The economic principle is that to be efficient, pricing should be based on marginal costs. There is nothing in this principle that supports implementing a fixed charge just because a cost has an accounting life of one year or more. FPL offers a cynical justification that if FPL cannot charge the minimum bill, they will just seek to further increase the fixed customer charge.[75] Finally, FPL encourages the Commission to turn its attention away, because the vast majority of customers will have usage that exceeds the minimum bill threshold.[76]

Q. What should the Commission do regarding FPL's minimum bill proposal?

A. The Commission should deny FPL's proposal to increase the minimum bill and should further direct FPL to eliminate the minimum bill, beyond a reasonable

[74] Cohen Direct at 19.
[75] *Id.*
[76] *Id.* at 20.

fixed customer charge, entirely.

IX. FPL's PROPOSAL FOR NEW LARGE LOAD RATE SCHEDULES

Q. Please describe FPL's proposal for new rate schedules applicable to large loads.

A. FPL proposes two new rate schedules, LLCS-1 and LLCS-2, that apply nominally to new or incremental load of 25 MW or greater, with a load factor of 85% or higher,[77] but in practical effect most likely to apply to data centers or similar facilities. The rates were developed to achieve three objectives:[78]

> (i) ensure that FPL has a tariff and service agreement available to serve customers of this magnitude should they request service in the future; (ii) ensure that the cost-causer bears primary responsibility and risk for the significant generation investments required to serve a customer of this size; and (iii) protect the general body of customers and mitigate risk of subsidization and stranded assets.

The LLCS-1 rate will be available for up to 3 GW of load and is geographically limited to counties proximate to existing transmission facilities and potential sites for incremental supporting generation.[79] It will have a stated rate which will be reset in a subsequent proceeding based on the characteristics of supplied load.[80]

The LLCS-2 rate will be available in areas outside those covered by LLCS-2 but is not capped in volume and will not have a stated rate.[81] Rates for

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[77] *Id.* at 23-28.
[78] *Id.* at 23-24.
[79] *Id.* at 24, 26.
[80] *Id.*
[81] *Id.* at 24-25.

LLCS-2 are also subject to reset in subsequent proceedings.[82]

Both LLCS rates will be initially set equal to those in rate GSLD-3, and will include base, demand, and non-fuel energy charges.[83] Both rate schedules will include an Incremental Generation Charge ("IGC") designed to recover the costs of incremental generation necessary to serve loads taking service from the rates.[84]

Q. What is your opinion of FPL's proposed LLCS rate schedules?

A. The rate schedules as described by FPL are a good start and, if properly applied, will protect the public interest. The problems created by poorly designed and applied large load rates have been well-documented.[85]

Q. Do you offer any recommendations to FPL and the Commission?

A. I offer the following recommendations to address what are increasingly common problems associated with rates applied to large loads:

- Cost allocation methods can unfairly allocate large load costs to residential and small commercial customers. The Commission must be diligent to address and prevent cross-subsidization that burdens small customers with large customer costs.
- Large load customers often enjoy special access to utility key accounts staff and can exercise undue influence on utility analysis and decision making. The processes for analyzing and setting rates must be transparent and subject to review and contest by stakeholders

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[82] *Id.* at 25.
[83] *Id.*
[84] *Id.*
[85] Exhibit KRR-5, Eliza Martin & Ari Peskoe, *Extracting Profits from the Public: How Utility Ratepayers are Paying for Big Tech's Power,* Harvard Law School Environmental and Energy Law Program (Mar. 2025), https://eelp.law.harvard.edu/wp-content/uploads/2025/03/Harvard-ELI-Extracting-Profits-from-the-Public.pdf.

representing all customer interests.

- Large load customers often seek rate pricing based on short-run marginal costs, especially as new resources with falling marginal costs, like solar, are added to the grid. The utility and the Commission must ensure that large loads pay a reasonable share of the embedded costs of the utility system.
- Utilities often serve as lobbying and advocacy supporters of favorable rates for large load customers. The Commission should forbid utilities from charging the general body of customers for lobbying and advocacy that may lead to cost-shifts and cross subsidization.
- Large loads require large amounts of energy and capacity. The Commission should ensure that the existing generation pool is not deaveraged in rates to favor new large loads. If incremental grid resources, including generation and transmission, are required, the general body of rate payers should be held harmless for paying the costs of those resources, especially if the large load stops being a customer before the costs of the new facilities are fully recovered.
- Large loads often take service at the higher—primary or transmission—levels of the grid. This may mean that FERC-regulated tariffs govern some of the rates applied to these customers. The Commission should require FPL to account for the impacts of such rates when retail rates are analyzed and set.
- Large loads generally can moderate their demand, especially at large facilities. The Commission and FPL should ensure that these customers agree to provide load flexibility benefits through curtailment of load

during periods of high system load and extreme weather.

- Large loads are often located near existing transmission and generation assets but are seldom electrically co-located with utility facilities. Reliability management countenances against actual co-location of large loads and interconnected utility generation. As a result, large loads must remain responsible for their full share of system energy, demand, and delivery costs.

X. FPL's SOLAR POWER FACILITIES PILOT PROGRAM SHOULD BE TERMINATED

Q. Please describe FPL's Solar Power Facilities program.

A. Starting with the 2021 rate case settlement, FPL offers the Solar Power Facilities Pilot program in which FPL will install utility-owned solar generation equipment on the private property of commercial and industrial customers under a special tariff. Although the program has enrolled only one customer in the past four years, in this proceeding FPL seeks to make the program permanent.[86]

Q. What is wrong with the Solar Power Facilities program?

A. The FPL Solar Power Facilities program is an unnecessary and apparently unwanted intrusion by a monopoly utility into a healthy free market for customer-sited solar generation.[87] The United States was founded on principles of capitalism and markets, and monopoly utilities with their immense market and political power should not be allowed to participate in competitive markets.

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[86] Oliver Direct at 42.

[87] Johanna Neumann & Tony Dutzik, *Rocftcp Solar on the Rise: Florida State Dashboard,* Environment Florida Research & Policy Center (Feb. 12, 2024), https://environmentamerica.org/florida/center/resources/rooftop-solar-on-the-rise/.

There is no evidence that the customer-sited solar market is a natural monopoly, or that FPL's Solar Power Facilities program fills a market need that the free market cannot or does not. In sum, the FPL's Solar Power Facilities program is not in the public interest.

Q. What should the Commission do?

A. The Commission should direct FPL to shut down the Solar Power Facilities program and sell the existing facilities for the one subscribed customer to a business in the competitive market.

XI. FPL CONSISTENTLY UNDER-FORECASTS ENERGY DEMAND

Q. How well does FPL perform in forecasting customer demand for energy?

A. According to data provided by FPL, the utility consistently under-estimates demand for energy by its customers, and FPL's forecasting error is significant.[88] This data shows that on average across zero- to three-year forecasts, FPL under-forecasts energy demand by 2.9%.[89] For example, FPL's forecasts for energy sales for 2024 have been equal to or greater than 3.0% for each year in the range of zero to three years out. The average level of error for 2024 under-forecasting was 3.6%, equal to more than 380,000 residential customer-months of energy use for the year at the assumed level of 1,000 kWh per month.[90]

Q. Do you have any ideas about what causes this error in energy forecasts?

A. In my experience, the causes of load forecasting errors fall in two categories: data and assumptions. I have no reason to doubt the quality of FPL's data,

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[88] FPL response to FEL 7th POD No. 62 – Retail Energy Sales – Non-Weather Normalized Comparison.

[89] *Id.*

[90] Calculated as ((129,416 GWh – 124,778 GWh) x 1,000,000)/12/1000 kWh = 386,500 customer-months.

though FPL should validate its data and data collection methods considering the extremely large errors in its forecasting. The best first area for analysis is in the assumptions about weather. FPL relies on a 20-year record of historical weather as the foundation for its energy sales forecasts, and that may be driving a significant component of the forecasting error.[91]

Q. Why would you focus on assumptions about weather and FPL reliance on a 20-year weather record?

A. There are two reasons that FPL's weather assumptions may be driving the errors in its energy forecasts. First, twenty years is a very long period for historical weather data in a world and region experiencing accelerating climate change.[92] FPL should evaluate a move to a 10-year record of historical data to more accurately capture rapid changes in climate and reserve the 20-year record for capturing the frequency of extreme weather events. Second, Florida's building stock is not as energy efficient as it could be because of Florida's poor record of implementing building energy efficiency programs.[93] That means that buildings in Florida are more susceptible to changing and extreme weather and will require much more energy to maintain comfort than efficient buildings would during these times.

Q. What are the consequences of FPL's significant energy sales forecasting errors?

A. Sales forecasting errors lead to inefficient prices under cost-of-service rate

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[91] Cohen Direct at Ex. TCC-4, p. 2-3.

[92] *See* Theara Coleman, *What Climate Change Means for Florida's Future: The Tide is Coming In,* The Week (updated Jul. 13, 2023), https://theweek.com/feature/briefing/1018352/what-climate-change-will-mean-for-the-future-of-florida; U.S. EPA, *What Climate Change Means for Florida,* EPA 430-F-16-011 (Aug. 2016), https://www.epa.gov/sites/default/files/2016-08/documents/climate-change-fl.pdf.

[93] *See* Mark Kresowik, et al., *2025 State Energy Efficiency Scorecard,* ACEEE (Mar. 2025), https://www.aceee.org/sites/default/files/pdfs/the_2025_state_scorecard.pdf.

making. Because a rate is, at its most basic, the result of dividing costs by expected sales, under-forecasting results in rates that are too high and that do not send accurate price signals to customers. Prices that are too high are not likely to result in significantly lower use by residential and small business customers because they generally have low demand elasticity—they don't change their consumption habits much due to electricity price changes. An even bigger problem is that by using forecasts that are too low, the utility can increase its revenues and profits and, as a result, earn more than it should between rate cases.

Q. What should the Commission with this evidence about FPL's consistent under-forecasting of energy sales?

A. The Commission should direct FPL to add 3% to its sales forecast, allocated according to 10-year historical data. The Commission should also open a proceeding led by Staff and engaging key stakeholders in developing recommendations to FPL for improvements in sales forecasts, especially in light of the effects of climate change. This effort should also seek to develop performance metrics with incentives for FPL to improve its sales forecasting. The Commission should direct FPL to comprehensively review its sales forecasting methodologies and make the changes needed to improve its forecasting accuracy.

Q. Does that conclude your testimony?

A. Yes.

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Nationally recognized leader and innovator in electricity and energy law, policy, and regulation. Experienced as a regulatory expert, utility executive, research and development manager, sustainability leader, senior government official, educator, and advocate. Law teaching experience at Pace University Elisabeth Haub School of Law, University of Houston Law Center, and U.S. Military Academy at West Point. Military veteran.

Employment

RÁBAGO ENERGY LLC

Principal: July 2012—Present. Consulting practice dedicated to providing business sustainability, expert witness, and regulatory advice and services to organizations in the clean and advanced energy sectors. Prepared and submitted testimony in more than 35 jurisdictions and 174 electricity and gas regulatory proceedings. Recognized national leader in development and implementation of innovative "Value of Solar" alternative to traditional net metering. Additional information at rabagoenergy.com.

- Chairman of the Board, Center for Resource Solutions (1997-present). Past chair of the Green-e Governance Board.
- Director, Colorado Electric Transmission Authority (2022-present).
- Director, Inside Climate News (2024-present)
- Advisor, Commission Shift (2021-present).
- Director, Solar United Neighbors (2018-2024).
- Director, Texas Solar Energy Society (2022-2024).

PACE ENERGY AND CLIMATE CENTER, PACE UNIVERSITY ELISABETH HAUB SCHOOL OF LAW

Senior Policy Advisor: September 2019—September 2020. Part-time advisor and staff member. Provided transitional expert witness, project management, and business development support on electric and gas regulatory and policy issues and activities.

Executive Director: May 2014—August 2019. Leader of a team of professional and technical experts and law students in energy and climate law, policy, and regulation. Secured funding for and managed execution of regulatory intervention, research, market development support, and advisory services. Taught Energy Law. Provided learning and development opportunities for law students. Additional activities:

- Director, Alliance for Clean Energy – New York (2018-2019).
- Director, Interstate Renewable Energy Council (IREC) (2012-2018).
- Co-Director and Principal Investigator, Northeast Solar Energy Market Coalition (2015-2017). The NESEMC was a US Department of Energy's SunShot Initiative Solar Market Pathways project. Funded under a cooperative agreement between the US DOE and Pace University, the NESEMC worked to harmonize solar market policy and advance supportive policy and regulatory practices in the northeast United States.

Karl R. Rábago

AUSTIN ENERGY – THE CITY OF AUSTIN, TEXAS

Vice President, Distributed Energy Services: April 2009—June 2012. Executive in one of the largest public power electric utilities, serving more than one million people in central Texas. Responsible for management and oversight of energy efficiency, demand response, and conservation programs; low-income weatherization; distributed solar and other renewable energy technologies; green buildings program; key accounts relationships; electric vehicle infrastructure; and market research and product development. Executive sponsor of Austin Energy's participation in an innovative federally funded smart grid demonstration project led by the Pecan Street Project. Led teams that successfully secured over $39 million in federal stimulus funds for energy efficiency, smart grid, and advanced electric transportation initiatives. Additional activities included:

- Director, Renewable Energy Markets Association. REMA is a trade association dedicated to maintaining and strengthening renewable energy markets in the United States.
- Member, Pedernales Electric Cooperative Member Advisory Board. Invited by the Board of Directors to sit on first-ever board to provide formal input and guidance on energy efficiency and renewable energy issues for the nation's largest electric cooperative.

THE AES CORPORATION

Director, Government & Regulatory Affairs: June 2006—December 2008. Director, Global Regulatory Affairs, provided regulatory support and group management to AES's international electric utility operations on five continents. Managing Director, Standards and Practices, for Greenhouse Gas Services, LLC, a GE Energy and AES venture committed to generating and marketing voluntary market greenhouse gas credits. Government and regulatory affairs manager for AES Wind Generation. Managed a portfolio of regulatory and legislative initiatives to support wind energy market development in Texas, across the United States, and in many international markets.

JICARILLA APACHE NATION UTILITY AUTHORITY

Director: 1998—2008. Located in New Mexico, the JANUA was an independent utility developing profitable and autonomous utility services that provided natural gas, water utility services, low-income housing, and energy planning for the Nation. Authored "First Steps" renewable energy and energy efficiency strategic plan with support from U.S. Department of Energy.

HOUSTON ADVANCED RESEARCH CENTER

Group Director, Energy and Buildings Solutions: December 2003—May 2006. Leader of energy and building science staff at a mission-driven not-for-profit contract research organization based in The Woodlands, Texas. Responsible for developing, maintaining, and expanding on technology development, application, and commercialization support programmatic activities, including the Center for Fuel Cell Research and Applications; the Gulf Coast Combined Heat and Power Application Center; and the High-Performance Green Buildings Practice. Secured funding for major new initiative in carbon nanotechnology applications in the energy sector.

- President, Texas Renewable Energy Industries Association. As elected president of the statewide business association, led and managed successful efforts to secure and implement significant expansion of the state's renewable portfolio standard as well as other policy, regulatory, and market development activities.
- Director, Southwest Biofuels Initiative. Established the Initiative as an umbrella structure for multiple biofuels related projects.

Karl R. Rábago

- Member, Committee to Study the Environmental Impacts of Wind Power, National Academies of Science National Research Council. The Committee was chartered by Congress and the Council on Environmental Quality to assess the impacts of wind power on the environment.
- Advisory Board Member, Environmental & Energy Law & Policy Journal, University of Houston Law Center.

CARGILL DOW LLC (NOW NATUREWORKS, LLC)

Sustainability Alliances Leader: April 2002—December 2003. Integrated sustainability principles into all aspects of a ground-breaking bio-based polymer manufacturing venture. Responsible for maintaining, enhancing, and building relationships with stakeholders in the worldwide sustainability community, as well as managing corporate and external sustainability initiatives.

- Successfully completed Minnesota Management Institute at University of Minnesota Carlson School of Management, an alternative to an executive MBA program that surveyed fundamentals and new developments in finance, accounting, operations management, strategic planning, and human resource management.

ROCKY MOUNTAIN INSTITUTE

Managing Director/Principal: October 1999–April 2002. Co-authored "Small Is Profitable," a comprehensive analysis of the benefits of distributed energy resources. Provided consulting and advisory services to help business and government clients achieve sustainability through application and incorporation of Natural Capitalism principles.

- President of the Board, Texas Ratepayers Organization to Save Energy. Texas R.O.S.E. is a non-profit organization advocating low-income consumer issues and energy efficiency programs.
- Co-Founder and Chair of the Advisory Board, Renewable Energy Policy Project-Center for Renewable Energy and Sustainable Technology. REPP-CREST was a national non-profit research and internet services organization.

CH2M HILL

Vice President, Energy, Environment and Systems Group: July 1998–August 1999. Responsible for providing consulting services to a wide range of energy-related businesses and organizations, and for creating new business opportunities in the energy industry for an established engineering and consulting firm. Completed comprehensive electric utility restructuring studies for Colorado and Alaska.

PLANERGY

Vice President, New Energy Markets: January 1998–July 1998. Responsible for developing and managing new business opportunities for the energy services market. Provided consulting and advisory services to utility and energy service companies.

ENVIRONMENTAL DEFENSE FUND

Energy Program Manager: March 1996–January 1998. Managed renewable energy, energy efficiency, and electric utility restructuring programs. Led regulatory intervention activities in Texas and California. In Texas, played a key role in crafting Deliberative Polling processes. Participated in national environmental and energy advocacy networks, including the Energy Advocates Network, the National Wind Coordinating Committee, the NCSL Advisory Committee on Energy, and the PV-COMPACT Coordinating Council. Frequently appeared before the Texas Legislature, Austin City Council, and regulatory commissions on electric restructuring issues.

Karl R. Rábago

UNITED STATES DEPARTMENT OF ENERGY

Deputy Assistant Secretary, Utility Technologies: January 1995–March 1996. Manager of the Department's programs in renewable energy technologies and systems, electric energy systems, energy efficiency, and integrated resource planning. Supervised technology research, development and deployment activities in photovoltaics, wind energy, geothermal energy, solar thermal energy, biomass energy, high-temperature superconductivity, transmission and distribution, hydrogen, and electric and magnetic fields. Managed, coordinated, and developed international agreements. Supervised development and deployment support activities at national laboratories. Developed, advocated, and managed a Congressional budget appropriation of approximately $300 million.

STATE OF TEXAS

Commissioner, Public Utility Commission of Texas. May 1992–December 1994. Appointed by Governor Ann W. Richards. Regulated electric and telephone utilities in Texas. Co-chair and organizer of the Texas Sustainable Energy Development Council. Vice-Chair of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Energy Conservation. Member and co-creator of the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology (PV-COMPACT).

LAW TEACHING

Professor for a Designated Service: Pace University Elisabeth Haub School of Law, 2014-2019. Non-tenured member of faculty. Taught Energy Law. Supervised a student intern practice.

Associate Professor of Law: University of Houston Law Center, 1990–1992. Full time, tenure track member of faculty. Courses taught: Criminal Law, Environmental Law, Criminal Procedure, Environmental Crimes Seminar, Wildlife Protection Law.

Assistant Professor: United States Military Academy, West Point, New York, 1988–1990. Member of the faculty in the Department of Law. Honorably discharged in August 1990, as Major in the Regular Army. Courses taught: Constitutional Law, Military Law, and Environmental Law Seminar.

LITIGATION

Trial Defense Attorney and Prosecutor, U.S. Army Judge Advocate General's Corps, Fort Polk, Louisiana, January 1985–July 1987. Assigned to Trial Defense Service and Office of the Staff Judge Advocate.

NON-LEGAL MILITARY SERVICE

Armored Cavalry Officer, 2d Squadron 9th Armored Cavalry, Fort Stewart, Georgia, May 1978–August 1981. Served as Logistics Staff Officer (S-4). Managed budget, supplies, fuel, ammunition, and other support for an Armored Cavalry Squadron. Served as Support Platoon Leader for the Squadron (logistical support), and as line Platoon Leader in an Armored Cavalry Troop. Graduate of Airborne and Ranger Schools. Special training in Air Mobilization Planning and Nuclear, Biological and Chemical Warfare.

Karl R. Rábago

Formal Education

LL.M., Environmental Law, Pace University School of Law, 1990: Curriculum designed to provide breadth and depth in study of theoretical and practical aspects of environmental law. Courses included: International and Comparative Environmental Law, Conservation Law, Land Use Law, Seminar in Electric Utility Regulation, Scientific and Technical Issues Affecting Environmental Law, Environmental Regulation of Real Estate, Hazardous Wastes Law. Individual research with Hudson Riverkeeper Fund, Garrison, New York, on federal regulation of cooling water intake structures for electric power plants.

LL.M., Military Law, U.S. Army Judge Advocate General's School, 1988: Curriculum designed to prepare Judge Advocates for senior level staff service. Courses included: Administrative Law, Defensive Federal Litigation, Government Information Practices, Advanced Federal Litigation, Federal Tort Claims Act Seminar, Legal Writing and Communications, Comparative International Law.

J.D. with Honors, University of Texas School of Law, 1984: Attended law school under the U.S. Army Funded Legal Education Program, a fully funded scholarship awarded to 25 or fewer officers each year. Served as Editor-in-Chief (1983–84); Articles Editor (1982–83); Member (1982) of the Review of Litigation. Moot Court, Mock Trial, Board of Advocates. Summer internship at Staff Judge Advocate's offices. Prosecuted first cases prior to entering law school.

B.B.A., Business Management, Texas A&M University, 1977: ROTC Scholarship (3–yr). Member: Corps of Cadets, Parson's Mounted Cavalry, Wings & Sabers Scholarship Society, Rudder's Rangers, Town Hall Society, Freshman Honor Society, Alpha Phi Omega service fraternity.

Karl R. Rábago

Selected Publications

Utilities are Shedding Crocodile Tears over Community Solar "Cost-Shift," Utility Dive Opinion (April 14, 2025).

The Future of Decentralized Electricity Distribution Networks: Ch. 14 – Performance-Based Regulation to Drive Transformation and Encourage DER Market Growth, contributing co-author with Jesse Hitchcock, Elsevier (2023).

Climate Change Law: An Introduction, contributing author (Introduction to Energy Law), Elgar (2021).

Distributed Generation Law, contributing author, American Bar Association Environment, Energy, and Resources Section (August 2020)

National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, contributing author, National Energy Screening Project (August 2020)

Achieving 100% Renewables: Supply-Shaping through Curtailment, with Richard Perez, Marc Perez, and Morgan Putnam, PV Tech Power, Vol. 19 (May 2019).

A Radical Idea to Get a High-Renewable Electric Grid: Build Way More Solar and Wind than Needed, with Richard Perez, The Conversation, online at http://bit.ly/2YjnM15 (May 29, 2019).

Reversing Energy System Inequity: Urgency and Opportunity During the Clean Energy Transition, with John Howat, John Colgan, Wendy Gerlitz, and Melanie Santiago-Mosier, National Consumer Law Center, online at www.nclc.org (Feb. 26, 2019).

Revisiting Bonbright's Principles of Public Utility Rates in a DER World, with Radina Valova, The Electricity Journal, Vol. 31, Issue 8, pp. 9-13 (Oct. 2018).

Achieving very high PV penetration – The need for an effective electricity remuneration framework and a central role for grid operators, with Richard Perez (corresponding author), Energy Policy, Vol. 96, pp. 27-35 (2016).

The Net Metering Riddle, Electricity Policy.com, April 2016.

The Clean Power Plan, Power Engineering Magazine (invited editorial), Vol. 119, Issue 12 (Dec. 2, 2015)

The 'Sharing Utility:' Enabling & Rewarding Utility Performance, Service & Value in a Distributed Energy Age, co-author, 51st State Initiative, Solar Electric Power Association (Feb. 27, 2015)

Rethinking the Grid: Encouraging Distributed Generation, Building Energy Magazine, Vol. 33, No. 1 Northeast Sustainable Energy Association (Spring 2015)

The Value of Solar Tariff: Net Metering 2.0, The ICER Chronicle, Ed. 1, p. 46 [International Confederation of Energy Regulators] (December 2013)

A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, co-author with Jason Keyes, Interstate Renewable Energy Council (October 2013)

The 'Value of Solar' Rate: Designing an Improved Residential Solar Tariff, Solar Industry, Vol. 6, No. 1 (Feb. 2013)

Jicarilla Apache Nation Utility Authority Strategic Plan for Energy Efficiency and Renewable Energy Development, lead author & project manager, U.S. Department of Energy First Steps Toward Developing Renewable Energy and Energy Efficiency on Tribal Lands Program (2008)

A Review of Barriers to Biofuels Market Development in the United States, 2 Environmental & Energy Law & Policy Journal 179 (2008)

Karl R. Rábago

A Strategy for Developing Stationary Biodiesel Generation, Cumberland Law Review, Vol. 36, p.461 (2006)

Evaluating Fuel Cell Performance through Industry Collaboration, co-author, Fuel Cell Magazine (2005)

Applications of Life Cycle Assessment to NatureWorks™ Polylactide (PLA) Production, co-author, Polymer Degradation and Stability 80, 403-19 (2003)

An Energy Resource Investment Strategy for the City of San Francisco: Scenario Analysis of Alternative Electric Resource Options, contributing author, Prepared for the San Francisco Public Utilities Commission, Rocky Mountain Institute (2002)

Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size, co-author, Rocky Mountain Institute (2002)

Socio-Economic and Legal Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado, with Thomas E. Feiler, Colorado Public Utilities Commission and Colorado Electricity Advisory Panel (April 1, 1999)

Study of Electric Utility Restructuring in Alaska, with Thomas E. Feiler, Legislative Joint Committee on electric Restructuring and the Alaska Public Utilities Commission (April 1, 1999)

New Markets and New Opportunities: Competition in the Electric Industry Opens the Way for Renewables and Empowers Customers, EEBA Excellence (Journal of the Energy Efficient Building Association) (Summer 1998)

Building a Better Future: Why Public Support for Renewable Energy Makes Sense, Spectrum: The Journal of State Government (Spring 1998)

The Green-e Program: An Opportunity for Customers, with Ryan Wiser and Jan Hamrin, Electricity Journal, Vol. 11, No. 1 (January/February 1998)

Being Virtual: Beyond Restructuring and How We Get There, Proceedings of the First Symposium on the Virtual Utility, Klewer Press (1997)

Information Technology, Public Utilities Fortnightly (March 15, 1996)

Better Decisions with Better Information: The Promise of GIS, with James P. Spiers, Public Utilities Fortnightly (November 1, 1993)

The Regulatory Environment for Utility Energy Efficiency Programs, Proceedings of the Meeting on the Efficient Use of Electric Energy, Inter-American Development Bank (May 1993)

An Alternative Framework for Low-Income Electric Ratepayer Services, with Danielle Jaussaud and Stephen Benenson, Proceedings of the Fourth National Conference on Integrated Resource Planning, National Association of Regulatory Utility Commissioners (September 1992)

What Comes Out Must Go In: The Federal Non-Regulation of Cooling Water Intakes Under Section 316 of the Clean Water Act, Harvard Environmental Law Review, Vol. 16, p. 429 (1992)

Least Cost Electricity for Texas, State Bar of Texas Environmental Law Journal, Vol. 22, p. 93 (1992)

Environmental Costs of Electricity, Pace University School of Law, Contributor–Impingement and Entrainment Impacts, Oceana Publications, Inc. (1990)

Testimony Submitted by Karl R. Rábago
(as of 8 June 2025)

Date	Proceeding	Case/Docket #	On Behalf Of:
Dec. 21, 2012	VA Electric & Power Special Solar Power Tariff	Virginia State Corporation Commission Case # PUE-2012-00064	Southern Environmental Law Center
May 10, 2013	Georgia Power Company 2013 IRP	Georgia Public Service Commission Docket # 36498	Georgia Solar Energy Industries Association
Jun. 23, 2013	Louisiana Public Service Commission Re-examination of Net Metering Rules	Louisiana Public Service Commission Docket # R-31417	Gulf States Solar Energy Industries Association
Aug. 29, 2013	DTE (Detroit Edison) 2013 Renewable Energy Plan Review (Michigan)	Michigan Public Utilities Commission Case # U-17302	Environmental Law and Policy Center
Sep. 5, 2013	CE (Consumers Energy) 2013 Renewable Energy Plan Review (Michigan)	Michigan Public Utilities Commission Case # U-17301	Environmental Law and Policy Center
Sep. 27, 2013	North Carolina Utilities Commission 2012 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 136	North Carolina Sustainable Energy Association
Oct. 18, 2013	Georgia Power Company 2013 Rate Case	Georgia Public Service Commission Docket # 36989	Georgia Solar Energy Industries Association
Nov. 4, 2013	PEPCO Rate Case (District of Columbia)	District of Columbia Public Service Commission Formal Case # 1103	Grid 2.0 Working Group & Sierra Club of Washington, D.C.
Apr. 24, 2014	Dominion Virginia Electric Power 2013 IRP	Virginia State Corporation Commission Case # PUE-2013-00088	Environmental Respondents
Apr. 25, 2014	North Carolina Utilities Commission 2014 Avoided Cost Case - Direct	North Carolina Utilities Commission Docket # E-100, Sub. 140	Southern Alliance for Clean Energy
May 7, 2014	Arizona Corporation Commission Investigation on the Value and Cost of Distributed Generation	Arizona Corporation Commission Docket # E-00000J-14-0023	Rábago Energy LLC (invited presentation and workshop participation)
Jun. 2, 2014	North Carolina Utilities Commission 2014 Avoided Cost Case – Response (Corrected)	North Carolina Utilities Commission Docket # E-100, Sub. 140	Southern Alliance for Clean Energy
Jun. 20, 2014	North Carolina Utilities Commission 2014 Avoided Cost Case – Rebuttal	North Carolina Utilities Commission Docket # E-100, Sub. 140	Southern Alliance for Clean Energy

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(as of 8 June 2025)

Jul. 23, 2014	Florida Energy Efficiency and Conservation Act, Goal Setting – FPL, Duke, TECO, Gulf	Florida Public Service Commission Docket # 130199-EI, 130200-EI, 130201-EI, 130202-EI	Southern Alliance for Clean Energy
Sep. 19, 2014	Ameren Missouri's Application for Authorization to Suspend Payment of Solar Rebates	Missouri Public Service Commission File No. ET-2014-0350, Tariff # YE-2014-0494	Missouri Solar Energy Industries Association
Aug. 6, 2014	Appalachian Power Company 2014 Biennial Rate Review	Virginia State Corporation Commission Case # PUE-2014-00026	Southern Environmental Law Center (Environmental Respondents)
Aug. 13, 2014	Wisconsin Public Service Corp. 2014 Rate Application	Wisconsin Public Service Commission Docket # 6690-UR-123	RENEW Wisconsin and Environmental Law & Policy Center
Aug. 28, 2014	WE Energies 2014 Rate Application	Wisconsin Public Service Commission Docket # 05-UR-107	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 18, 2014	Madison Gas & Electric Company 2014 Rate Application	Wisconsin Public Service Commission Docket # 3720-UR-120	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 29, 2014	SOLAR, LLC v. Missouri Public Service Commission	Missouri District Court Case # 14AC-CC00316	SOLAR, LLC
Jan. 28, 2016 (date of CPUC order)	Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs, etc.	California Public Utilities Commission Rulemaking 14-07-002	The Utility Reform Network (TURN)
Mar. 20, 2015	Orange and Rockland Utilities 2015 Rate Application	New York Public Service Commission Case # 14-E-0493	Pace Energy and Climate Center
May 22, 2015	DTE Electric Company Rate Application	Michigan Public Service Commission Case # U-17767	Michigan Environmental Council, NRDC, Sierra Club, and ELPC
Jul. 20, 2015	Hawaiian Electric Company and NextEra Application for Change of Control	Hawai'i Public Utilities Commission Docket # 2015-0022	Hawai'i Department of Business, Economic Development, and Tourism
Sep. 2, 2015	Wisconsin Public Service Company Rate Application	Wisconsin Public Service Commission Case # 6690-UR-124	ELPC
Sep. 15, 2015	Dominion Virginia Electric Power 2015 IRP	Virginia State Corporation Commission Case # PUE-2015-00035	Environmental Respondents
Sep. 16, 2015	NYSEG & RGE Rate Cases	New York Public Service Commission Cases 15-E-0283, -0285	Pace Energy and Climate Center

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Oct. 14, 2015	Florida Power & Light Application for CCPN for Lake Okeechobee Plant	Florida Public Service Commission Case 150196-EI	Environmental Confederation of Southwest Florida
Oct. 27, 2015	Appalachian Power Company 2015 IRP	Virginia State Corporation Commission Case # PUE-2015-00036	Environmental Respondents
Nov. 23, 2015	Narragansett Electric Power/National Grid Rate Design Application	Rhode Island Public Utilities Commission Docket No. 4568	Wind Energy Development, LLC
Dec. 8, 2015	State of West Virginia, et al., v. U.S. EPA, et al.	U.S. Court of Appeals for the District of Columbia Circuit Case No. 15-1363 and Consolidated Cases	Declaration in Support of Environmental and Public Health Intervenors in Support of Movant Respondent-Intervenors' Responses in Opposition to Motions for Stay
Dec. 28, 2015	Ohio Power/AEP Affiliate PPA Application	Public Utilities Commission of Ohio Case No. 14-1693-EL-RDR	Environmental Law and Policy Center
Jan. 19, 2016	Ohio Edison Company, Cleveland Electric Illuminating Company, and Toledo Edison Company Application for Electric Security Plan (FirstEnergy Affiliate PPA)	Public Utilities Commission of Ohio Case No. 14-1297-EL-SSO	Environmental Law and Policy Center
Jan. 22, 2016	Northern Indiana Public Service Company (NIPSCO) Rate Case	Indiana Utility Regulatory Commission Cause No. 44688	Citizens Action Coalition and Environmental Law and Policy Center
Mar. 18, 2016	Northern Indiana Public Service Company (NIPSCO) Rate Case – Settlement Testimony	Indiana Utility Regulatory Commission Cause No. 44688	Joint Intervenors – Citizens Action Coalition and Environmental Law and Policy Center
Mar. 18, 2016	Comments on Pilot Rate Proposals by MidAmerican and Alliant	Iowa Utility Board NOI-2014-0001	Environmental Law and Policy Center
May 27, 2016	Consolidated Edison of New York Rate Case	New York Public Service Commission Case No. 16-E-0060	Pace Energy and Climate Center
Jun. 21, 2016	Federal Trade Commission: Workshop on Competition and Consumer Protection Issues in Solar Energy - Invited workshop presentation	Federal Trade Commission - Solar Electricity Project No. P161200	Pace Energy and Climate Center
Aug. 17, 2016	Dominion Virginia Electric Power 2016 IRP	Virginia State Corporation Commission Case # PUE-2016-00049	Environmental Respondents

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Sep. 13, 2016	Appalachian Power Company 2016 IRP	Virginia State Corporation Commission Case # PUE-2016-00050	Environmental Respondents
Oct. 27, 2016	Consumers Energy PURPA Compliance Filing	Michigan Public Service Commission Case No. U-18090	Environmental Law & Policy Center, "Joint Intervenors"
Oct. 28, 2016	Delmarva, PEPCO (PHI) Utility Transformation Filing – Review of Filing & Utilities of the Future Whitepaper	Maryland Public Service Commission Case PC 44	Public Interest Advocates
Dec. 1, 2016	DTE Electric Company PURPA Compliance Filing	Michigan Public Service Commission Case No. U-18091	Environmental Law & Policy Center, "Joint Intervenors"
Dec. 16, 2016	Development of New Alternative Net Metering Tariffs - Rebuttal of Unitil Testimony	New Hampshire Public Utilities Commission Docket No. DE 16-576	New Hampshire Sustainable Energy Association ("NHSEA")
Jan. 13, 2017	Gulf Power Company Rate Case	Florida Public Service Commission Docket No. 160186-EI	Earthjustice, Southern Alliance for Clean Energy, League of Women Voters-Florida
Jan. 13, 2017	Alpena Power Company PURPA Compliance Filing	Michigan Public Service Commission Case No. U-18089	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Indiana Michigan Power Company PURPA Compliance Filing	Michigan Public Service Commission Case No. U-18092	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Northern States Power Company PURPA Compliance Filing	Michigan Public Service Commission Case No. U-18093	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Upper Peninsula Power Company PURPA Compliance Filing	Michigan Public Service Commission Case No. U-18094	Environmental Law & Policy Center, "Joint Intervenors"
Mar. 10, 2017	Eversource Energy Grid Modernization Plan	Massachusetts Department of Public Utilities Case No. 15-122/15-123	Cape Light Compact
Apr. 27, 2017	Eversource Rate Case & Grid Modernization Investments	Massachusetts Department of Public Utilities Case No. 17-05	Cape Light Compact
May 2, 2017	AEP Ohio Power Electric Security Plan	Public Utilities Commission of Ohio Case No. 16-1852-EL-SSO	Environmental Law & Policy Center
Jun. 2, 2017	Vectren Energy TDSIC Plan	Indiana Utility Regulatory Commission Cause No. 44910	Citizens Action Coalition & Valley Watch
Jul. 26, 2017	Vectren Energy 2018-2020 Energy Efficiency Plan	Indiana Utility Regulatory Commission Cause No. 44927	Citizens Action Coalition

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Jul. 28, 2017	Vectren Energy 2016-2017 Energy Efficiency Plan	Indiana Utility Regulatory Commission Cause No. 44645	Citizens Action Coalition
Aug. 1, 2017	Interstate Power & Light (Alliant) 2017 Rate Application	Iowa Utilities Board Docket No. RPU-2017-0001	Environmental Law & Policy Center, Iowa Environmental Council, Natural Resources Defense Council, and Solar Energy Industries Assoc.
Aug. 11, 2017	Dominion Virginia Electric Power 2017 IRP	Virginia State Corporation Commission Case # PUR-2017-00051	Environmental Respondents
Aug. 18, 2017	Appalachian Power Company 2017 IRP	Virginia State Corporation Commission Case # PUR-2017-00045	Environmental Respondents
Aug. 23, 2017	Pennsylvania Solar Future Project	Pennsylvania Dept. of Environmental Protection - Alternative Ratemaking Webinar	Pace Energy and Climate Center
Aug. 25, 2017	Niagara Mohawk Power Co. d/b/a National Grid Rate Case	New York Public Service Commission Case # 17-E-0238, 17-G-0239	Pace Energy and Climate Center
Sep. 15, 2017	Niagara Mohawk Power Co. d/b/a National Grid Rate Case	New York Public Service Commission Case # 17-E-0238, 17-G-0239	Pace Energy and Climate Center
Oct. 20, 2017	Missouri PSC Working Case to Explore Emerging Issues in Utility Regulation	Missouri Public Service Commission File No. EW-2017-0245	Renew Missouri
Nov. 21, 2017	Central Hudson Gas & Electric Co. Electric and Gas Rates Cases	New York Public Service Commission Case # 17-E-0459, -0460	Pace Energy and Climate Center
Jan. 16, 2018	Great Plains Energy, Inc. Merger with Westar Energy, Inc.	Missouri Public Service Commission Case # EM-2018-0012	Renew Missouri Advocates
Jan. 19, 2018	U.S. House of Representatives, Energy and Commerce Committee	Hearing on "The PURPA Modernization Act of 2017," H.R. 4476	Rábago Energy LLC
Jan. 29, 2018	Joint Petition of Electric Distribution Companies for Approval of a Model SMART Tariff	Massachusetts Department of Public Utilities Case No. 17-140	Boston Community Capital Solar Energy Advantage Inc. (Jointly authored with Sheryl Musgrove)
Feb. 21, 2018	Joint Petition of Electric Distribution Companies for Approval of a Model SMART Tariff	Massachusetts Department of Public Utilities Case No. 17-140 - Surrebuttal	Boston Community Capital Solar Energy Advantage Inc. (Jointly authored with Sheryl Musgrove)

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Apr. 6, 2018	Narragansett Electric Co., d/b/a National Grid Rate Case Filing	Rhode Island Public Utilities Commission Docket No. 4770	New Energy Rhode Island ("NERI")
Apr. 25, 2018	Narragansett Electric Co., d/b/a National Grid Power Sector Transformation Plan	Rhode Island Public Utilities Commission Docket No. 4780	New Energy Rhode Island ("NERI")
Apr. 26, 2018	U.S. EPA Proposed Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Stories: Electric Utility Generating Units, 82 Fed. Reg. 48,035 (Oct. 16, 2017) – "Clean Power Plan"	U.S. Environmental Protection Agency Docket No. EPA-HQ-OAR-2016-0592	Karl R. Rábago
May 25, 2018	Orange & Rockland Utilities, Inc. Rate Case Filing	New York Public Service Commission Case Nos. 18-E-0067, 18-G-0068	Pace Energy and Climate Center
Jun. 15, 2018	Orange & Rockland Utilities, Inc. Rate Case Filing	New York Public Service Commission Case Nos. 18-E-0067, 18-G-0068 – Rebuttal Testimony	Pace Energy and Climate Center
Aug. 10, 2018	Dominion Virginia Electric Power 2018 IRP	Virginia State Corporation Commission Case # PUR-2018-00065	Environmental Respondents
Sep. 20, 2018	Consumers Energy Company Rate Case	Michigan Public Service Commission Case No. U-20134	Environmental Law & Policy Center
Sep. 27, 2018	Potomac Electric Power Co. Notice to Construct Two 230 kV Underground Circuits	District of Columbia Public Service Commission Formal Case No. 1144	Solar United Neighbors of D.C.
Nov. 7, 2018	DTE Detroit Edison Rate Case	Michigan Public Service Commission Case No. U-20162	Natural Resources Defense Council, Michigan Environmental Council, Sierra Club
Nov. 13, 2018	In re: Rate Rider RGB (Supplementary, Back-Up, or Maintenance Power	Alabama Public Service Commission Docket No. U-4226	James H. Bankston, Ralph B. Pfeiffer, Jr., GASP, Inc. (Southern Environmental Law Center)
Mar. 26, 2019	Guam Power Authority Petition to Modify Net Metering	Guam Public Utilities Commission Docket GPA 19-04	Micronesia Renewable Energy, Inc.
Apr. 4, 2019	Community Power Network & League of Women Voters of Florida v. JEA	Circuit Court Duval County of Florida Case No. 2018-CA-002497 Div: CV-D	Earthjustice
Apr. 16, 2019	Dominion Virginia Electric Power 2018 IRP – Compliance Filing	Virginia State Corporation Commission Case # PUR-2018-00065	Environmental Respondents

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Apr. 25, 2019	Georgia Power 2019 IRP	Georgia Public Service Commission Docket No. 42310	GSEA & GSEIA
May 10, 2019	NV Energy NV GreenEnergy 2.0 Rider	Nevada Public Utilities Commission Docket Nos. 18-11015, 18-11016	Vote Solar
May 24, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Misc. Issues	New York Public Service Commission Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center
May 24, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Low- and Moderate-Income Panel	New York Public Service Commission Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center
May 30, 2019	Connecticut DEEP Shared Clean Energy Facility Program Proposal	Connecticut Department of Energy and Environmental Protection Docket No. 19-07-01	Connecticut Fund for the Environment
Jun. 3, 2019	New Orleans City Council Rulemaking to Establish Renewable Portfolio Standards	New Orleans City Council Docket No. UD-19-01	National Audubon Society and Audubon Louisiana
Jun. 14, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Rebuttal Testimony	New York Public Service Commission Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center
Jun. 24, 2019	Program to Encourage Clean Energy in Westchester County Pursuant to Public Service law Section 74-a; Staff Investigation into a Moratorium on New Natural Gas Services in the Consolidated Edison Company of New York, Inc. Service Territory	New York Public Service Commission Case Nos. 19-M-0265, 19-G-0080	Earthjustice and Pace Energy and Climate Center
Jul. 12, 2019	Application of Virginia Electric and Power Company for the Determination of the Fair Rate of Return on Common Equity	Virginia State Corporation Commission Case # PUR-2019-00050	Virginia Poverty Law Center
Jul. 15, 2019	New Orleans City Council Rulemaking to Establish Renewable Portfolio Standards – Reply Comments	New Orleans City Council Docket No. UD-19-01	National Audubon Society and Audubon Louisiana
Aug. 1, 2019	Interstate Power and Light Company – General Rate Case	Iowa Utilities Board Docket No. RPU-2019-0001	Environmental Law & Policy Center and Iowa Environmental Council
Aug. 19, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Surrebuttal	New York Public Service Commission Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center

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Aug. 21, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources - Comments	Connecticut Department of Energy and Environmental Protection/Public Utility Regulatory Authority Docket No. 19-06-29	Connecticut Fund for the Environment and Save Our Sound
Sep. 10, 2019	Interstate Power and Light Company – General Rate Case - Rebuttal	Iowa Utilities Board Docket No. RPU-2019-0001	Environmental Law & Policy Center and Iowa Environmental Council
Sep. 18, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources – Comments and Response to Draft Study Outline	Connecticut Department of Energy and Environmental Protection/Public Utility Regulatory Authority Docket No. 19-06-29	Connecticut Fund for the Environment, Save Our Sound, E4theFuture, NE Clean Energy Council, NE Energy Efficiency Partnership, and Acadia Center
Sep. 20, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources – Participation in Technical Workshop 1	Connecticut Department of Energy and Environmental Protection/Public Utility Regulatory Authority Docket No. 19-06-29 http://www.ctn.state.ct.us/ctnplayer.asp?odID=16715	Connecticut Fund for the Environment and Save Our Sound
Oct. 4, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources – Participation in Technical Workshop 2	Connecticut Department of Energy and Environmental Protection/Public Utility Regulatory Authority Docket No. 19-06-29 http://www.ctn.state.ct.us/ctnplayer.asp?odID=16766	Connecticut Fund for the Environment and Save Our Sound
Oct. 15, 2019	Electronic Consideration of the Implementation of the Net Metering Act (KY SB 100)	Kentucky Public Service Commission Case No. 2019-00256	Kentuckians for the Commonwealth & Mountain Association for Community Economic Development
Oct. 15, 2019	New Orleans City Council Rulemaking to Establish Renewable Portfolio Standards – Comments on City Council Utility Advisors' Report	New Orleans City Council Docket No. UD-19-01	National Audubon Society and Audubon Louisiana, Vote Solar, 350 New Orleans, Alliance for Clean Energy, PosiGen, and Sierra Club
Oct. 17, 2019	Indiana Michigan Power Co. General Rate Case	Michigan Public Service Company Case No. U-20359	Environmental Law & Policy Center, The Ecology Center, the Solar Energy Industries Association, and Vote Solar
Dec. 4, 2019	Alabama Power Company Petition for Certificate of Convenience and Necessity	Alabama Public Service Commission Docket No. 32953	Energy Alabama and Gasp, Inc.

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Dec. 5, 2019	In the Matter of Net Metering and the Implementation of Act 827 of 2015	Arkansas Public Service Commission Docket No. 16-027-R	National Audubon Society and Arkansas Advanced Energy Association
Dec. 6, 2019	Proposed Revisions to Vermont Public Utility Commission Rule 5.100	Vermont Public Utility Commission Case No. 19-0855-RULE	Renewable Energy Vermont ("REV")
Jan. 15, 2020	Puget Sound Energy General Rate Case	Washington Utilities and Transportation Commission Docket Nos. UE-190529 & UG-190530	Puget Sound Energy
Feb. 11, 2020	Application of Entergy Arkansas, LLC for a Proposed Tariff Amendment: Solar Energy Purchase Option – Direct Testimony	Arkansas Public Service Commission Docket No. 19-042-TF	Arkansas Advanced Energy Association
Mar. 17, 2020	Application of Entergy Arkansas, LLC for a Proposed Tariff Amendment: Solar Energy Purchase Option – Surrebuttal Testimony	Arkansas Public Service Commission Docket No. 19-042-TF	Arkansas Advanced Energy Association
Jun. 16, 2020	PECO Energy Default Supply Plan V – Direct Testimony	Pennsylvania Public Utility Commission Docket No. P-2020-3019290	Environmental Respondents / Earthjustice
Jun. 24, 2020	Consumers Energy Company General Rate Case – Direct Testimony	Michigan Public Service Commission Case No. U-20697	Joint Clean Energy Organizations / Environmental Law & Policy Center
Jul. 14, 2020	Consumers Energy Company General Rate Case – Rebuttal Testimony	Michigan Public Service Commission Case No. U-20697	Joint Clean Energy Organizations / Environmental Law & Policy Center
Jul. 23, 2020	PECO Energy Default Supply Plan V – Surrebuttal Testimony	Pennsylvania Public Utility Commission Docket No. P-2020-3019290	Environmental Stakeholders / Earthjustice
Sep. 15, 2020	Dominion Virginia Electric Power 2020 IRP – Direct Testimony	Virginia State Corporation Commission Case # PUR-2020-00035	Environmental Respondents
Sep. 18, 2020	Avoided Cost Proceeding for Georgia Power – Direct Testimony	Georgia Public Service Commission Docket No. 4822	Georgia Solar Energy Industries Association, Inc.
Sep. 29, 2020	Madison Gas and Electric – General Rate Case – Affidavit in Opposition to Electric Rates Settlement	Wisconsin Public Service Commission Docket No. 3270-UR-123	Sierra Club
Sep. 30, 2020	Madison Gas and Electric – General Rate Case – Gas Rates	Wisconsin Public Service Commission Docket No. 3270-UR-123	Sierra Club
Oct. 2, 2020	Duke Energy Florida Petition for Approval of Clean Energy Connect Program	Florida Public Service Commission Docket No. 20200176-EI	League of United Latin American Citizens of Florida

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(as of 8 June 2025)

Oct. 2, 2020	Ameren Illinois – Investigation re: Calculation of Distributed Generation Rebates	Illinois Commerce Commission Docket No. 20-0389	Joint Solar Parties
Dec. 9, 2020	Arkansas – In the Matter of a Rulemaking to Adopt an Evaluation, Measurement, and Verification Protocol and Propose M&V Amendments to the Commission's Rules for Conservation and Energy Efficiency Programs; In the Matter of the Continuation, Expansion, and Enhancement of Public Utility Energy Efficiency Programs in Arkansas	Arkansas Public Service Commission Docket Nos. 10-100-R, 13-002-U	Arkansas Advanced Energy Association
Dec. 22, 2020	Appalachian Power Company 2020 Virginia Clean Economy Act Compliance Plan	Virginia State Corporation Commission Case No. PUR-2020-00135	Environmental Respondent
Jan. 4, 2021	Dominion Virginia Electric Power Company Clean Economy Compliance Plan	Virginia State Corporation Commission Case No. PUR-2020-00134	Environmental Respondent
Feb. 5, 2021	Ameren Illinois – Investigation re: Calculation of Distributed Generation Rebates - Rebuttal	Illinois Commerce Commission Docket No. 20-0389	Joint Solar Parties
Feb. 15, 2021	Kentucky Power Company General Rate Case	Kentucky Public Service Commission Case No. 2020-00174	Joint Intervenors – Mountain Association, Kentuckians for the Commonwealth, Kentucky Solar Energy Society
Mar. 2, 2021	Dominion Virginia Electric Power Company Rider RGGI Proposal	Virginia State Corporation Commission Case No. PUR-2020-00169	Environmental Respondent
Mar. 5, 2021	Kentucky Utilities Company and Louisville Gas and Electric Company General Rate Cases	Kentucky Public Service Commission Case Nos. 2020-00349, 2020-00350	Joint Intervenors – Mountain Association, Kentuckians for the Commonwealth, Kentucky Solar Energy Society
Apr. 5, 2021	Docket to Review the Efficacy and Fairness of the Net Metering and Interconnection Rules – Comments	Mississippi Public Service Commission Docket No. 2021-AD-19	Entegrity Energy Partners, LLC & Audubon Delta / National Audubon Society
Apr. 13, 2021	Petition of Guam Power Authority for Creation of a New Energy Storage Rate – Comments of Micronesia Renewable Energy, Inc.	Guam Public Utilities Commission Docket No. 20-09	Micronesia Renewable Energy, Inc.
May 25, 2021	Petition of Episcopal Diocese of Rhode Island for Declaratory Judgment on Transmission System Costs and Related "Affected System Operator" Studies	Rhode Island Public Utility Commission Docket No. 4981	Episcopal Diocese of Rhode Island

Testimony Submitted by Karl R. Rábago

(as of 8 June 2025)

Jun. 21, 2021	Petition for Rate Increase by Florida Power & Light Company – Direct Testimony	Florida Public Service Commission Docket No. 20210015-EI	Florida Rising, Inc., League of United Latin American Citizens of Florida, and Environmental Confederation of Southwest Florida, Inc.
Jun. 22, 2021	Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution of Electricity and Other Relief	Michigan Public Service Commission Case No. U-20963	The Environmental Law and Policy Center (EPLC)
Jun. 28, 2021	Pennsylvania Public Utility Commission v. PECO Energy Company (GRC)	Pennsylvania Utility Commission Docket No. R-2021-3024601	Clean Energy Advocates
Jul. 12, 2021	Application of Consumers Energy Company for Authority to Increase Its Rates for the Generation and Distribution of Electricity and Other Relief – Rebuttal	Michigan Public Service Commission Case No. U-20963	The Environmental Law and Policy Center (EPLC)
Jul. 28, 2021	Application of Shenandoah Valley Electric Cooperative for a General Increase in Rates	Virginia State Corporation Commission Case No. PUR-2021-00054	Solar United Neighbors of Virginia (SUN-VA)
Aug. 5, 2021	Kentucky Utilities Company and Louisville Gas and Electric Company General Rate Cases – Supp. Proceeding on Net Energy Metering	Kentucky Public Service Commission Case Nos. 2020-00349, 2020-00350	Joint Intervenors – Mountain Association, Kentuckians for the Commonwealth, Kentucky Solar Energy Society
Sep. 2, 2021	Madison Gas & Electric Co. – General Rate Case	Wisconsin Public Service Commission Docket No. 3270-UR-124	Sierra Club
Sep. 3, 2021	Dominion Virginia Electric Power Company – Triennial Rate Review – Direct Testimony on ROE	Virginia State Corporation Commission Case No. PUR-2021-00058	Virginia Poverty Law Center
Sep. 13, 2021	Petition for Rate Increase by Florida Power & Light Company – Settlement Testimony	Florida Public Service Commission Docket No. 20210015-EI	Florida Rising, Inc., League of United Latin American Citizens of Florida, and Environmental Confederation of Southwest Florida, Inc.
Sep. 20, 2021	Madison Gas & Electric Co. – General Rate Case – Surrebuttal Testimony	Wisconsin Public Service Commission Docket No. 3270-UR-124	Sierra Club
Sep. 27, 2021	Dakota Energy Cooperative, Inc. v. East River Electric Power Cooperative, Inc. and Basin Electric Power Cooperative – Expert Report	US. District Court, District of South Dakota (Southern Division) Case 4:20-CV-04192-LLP	Dakota Energy Cooperative, Inc.

Testimony Submitted by Karl R. Rábago

(as of 8 June 2025)

Oct. 5, 2021	In the Matter of establishing regulations for a shared solar program pursuant to § 56-594.3 of the Code of Virginia	Virginia State Corporation Commission Case No. PUR-2020-00125	Coalition for Community Solar Access
Nov. 1, 2021	Dakota Energy Cooperative, Inc. v. East River Electric Power Cooperative, Inc. and Basin Electric Power Cooperative – Surrebuttal Expert Report	US. District Court, District of South Dakota (Southern Division) Case 4:20-CV-04192-LLP	Dakota Energy Cooperative, Inc.
Nov. 16, 2021	Petition of Virginia Electric and Power Company for approval of the RPS Development Plan, approval & certification of proposed CE-2 Solar Projects pursuant to § 56-580 D and 56-46.1 of the Code of Virginia	Virginia State Corporation Commission Case No. PUR-2021-00146	Appalachian Voices
Jan. 20, 2022	Alabama Power Company Petition for a Certificate of Convenience and Necessity	Alabama Public Service Commission Docket No. 33182	Energy Alabama, GASP
Mar. 1, 2022	In the Matter of establishing regulations for a multi-family shared solar program pursuant to § 56-585.1:12 of the Code of Virginia	Virginia State Corporation Commission Case No. PUR-2020-00125	Appalachian Voices
Mar. 29, 2022	Review of Duke Energy Carolina, LLC & Duke Energy Progress, LLC Joint Application for Approval of NEM Tariff Revisions and Recommendations for Investigation of Costs and Benefits of Customer-Sited Generation – Expert Report	North Carolina Utilities Commission Docket No. E-100, Sub. 180	Environmental Working Group
Mar. 30, 2022	Ameren Illinois Company Petition for Approval of Performance and Tracking Metrics Pursuant to 220 ILCS 5/16-108.188(e) – Direct Testimony	Illinois Commerce Commission Docket No. 22-0063	Joint Solar Parties
Apr. 6, 2022	Commonwealth Edison Company Petition for the Establishment of Performance Metrics under Section 16-108.18(e) of the Public Utilities Act	Illinois Commerce Commission Docket No. 22-0067	Joint Solar Parties

Testimony Submitted by Karl R. Rábago

(as of 8 June 2025)

May 6, 2022	Review of Duke Energy Carolina, LLC & Duke Energy Progress, LLC Joint Application for Approval of NEM Tariff Revisions and Recommendations for Investigation of Costs and Benefits of Customer-Sited Generation – Reply Report	North Carolina Utilities Commission Docket No. E-100, Sub. 180	Environmental Working Group
May 25, 2022	Ameren Illinois Company Petition for Approval of Performance and Tracking Metrics Pursuant to 220 ILCS 5/16-108.188(e) – Rebuttal Testimony	Illinois Commerce Commission Docket No. 22-0063	Joint Solar Parties
May 27, 2022	Review of Duke Energy Carolina, LLC & Duke Energy Progress, LLC Joint Application for Approval of NEM Tariff Revisions and Recommendations for Investigation of Costs and Benefits of Customer-Sited Generation – Surreply Report	North Carolina Utilities Commission Docket No. E-100, Sub. 180	Environmental Working Group
Jun. 6, 2022	Commonwealth Edison Company Petition for the Establishment of Performance Metrics under Section 16-108.18(e) of the Public Utilities Act – Rebuttal Testimony	Illinois Commerce Commission Docket No. 22-0063	Joint Solar Parties
Jun. 22, 2022	In the Matter of Austin Energy Base Rate Case Filing Dated April 18, 2022	City of Austin Hearing Examiner	Sierra Club, Public Citizen, and Solar United Neighbors
Oct. 3, 2022	In the Matter of the Application of Northern States Power Company (Xcel) for Authority to Increase Rates for Electric Service in Minnesota	Minnesota Public Utilities Commission Docket No. E002/GR-21-630.	Just Solar Coalition
Oct. 13, 2022	Verified Petition of Vote Solar of Distributed Energy Resource Systems in Wisconsin – Rebuttal	Wisconsin PSC Docket No. 9300-DR-106	Vote Solar
Oct. 21, 2022	Verified Petition of Vote Solar of Distributed Energy Resource Systems in Wisconsin - Surrebuttal	Wisconsin PSC Docket No. 9300-DR-106	Vote Solar
Nov. 14, 2022	In the Matter of the Application of Columbia Gas of Ohio, Inc. for Authority to Amend its Filed Tariffs to Increase the Rates and Charges for Gas Services and Related Matters	Public Utilities Commission of Ohio Case No. 21-637-GA-AIR	Environmental Law & Policy Center

Testimony Submitted by Karl R. Rábago

(as of 8 June 2025)

Dec. 6, 2022	In the Matter of the Application of Northern States Power Company (Xcel) for Authority to Increase Rates for Electric Service in Minnesota - Surrebuttal	Minnesota Public Utilities Commission Docket No. E002/GR-21-630.	Just Solar Coalition
Dec. 19, 2022	Application of NorthWestern Energy for Authority to Increase Retail Electric and Natural Gas Utility Service Rates - Direct	Montana Public Service Commission Docket No. 2022.07.078	Montana Environmental Information Center (MEIC), Earthjustice
Jan. 11, 2023	Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to Its Operations throughout the State of Arizona and for Related Approvals – Direct Testimony on ROE & Equity Ratio	Arizona Corporation Commission Docket No. E-01933A-22-0107	Arizona Solar Energy Industries Association & Solar Energy Industries Association
Jan. 27, 2023	Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to Its Operations throughout the State of Arizona and for Related Approvals – Direct Testimony on Community Solar	Arizona Corporation Commission Docket No. E-01933A-22-0107	Arizona Solar Energy Industries Association & Solar Energy Industries Association
Mar. 6, 2023	Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to Its Operations throughout the State of Arizona and for Related Approvals – Surrebuttal Testimony	Arizona Corporation Commission Docket No. E-01933A-22-0107	Arizona Solar Energy Industries Association & Solar Energy Industries Association

Testimony Submitted by Karl R. Rábago

(as of 8 June 2025)

May 9, 2023	The Peoples Gas Light and Coke Company – Proposed General Increase in Rates and Revisions to Service Classifications, Riders, and Terms and Conditions of Service – Direct Testimony	Illinois Commerce Commission Docket No. 23-0069	City of Chicago
July 17, 2023	The Peoples Gas Light and Coke Company – Proposed General Increase in Rates and Revisions to Service Classifications, Riders, and Terms and Conditions of Service – Rebuttal Testimony	Illinois Commerce Commission Docket No. 23-0069	City of Chicago
Aug. 25, 2023	In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and to Revise Its Terms – Direct Testimony	Maryland Public Service Commission Case No. 9704	Chesapeake Climate Action Network
Aug. 28, 2023	Application of Madison Gas and Electric Company for Authority to Adjust Electric and Natural Gas Rates – Direct Testimony	Public Service Commission of Wisconsin Docket No. 3270-UR-125	City of Madison
Sep. 16, 2023	Application of Madison Gas and Electric Company for Authority to Adjust Electric and Natural Gas Rates – Surrebuttal Testimony	Public Service Commission of Wisconsin Docket No. 3270-UR-125	City of Madison
Oct. 10, 2023	In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and to Revise Its Terms – Surrebuttal Testimony	Maryland Public Service Commission Case No. 9704	Chesapeake Climate Action Network
Apr. 16, 2024	In Re: Interstate Power & Light Company (General Rate Case) – Direct Testimony	Iowa Utilities Board Docket No. RPU-2023-0002	Clean Energy Districts of Iowa (CEDI) Coalition
Apr. 26, 2024	PECO Energy Default Supply Plan VI – Direct Testimony	Pennsylvania Public Utility Commission Docket No. P-2024-3046008	Energy Justice Advocates / Earthjustice
Apr. 30, 2024	In Re: Interstate Power & Light Company (General Rate Case) – Cross-Rebuttal Testimony	Iowa Utilities Board Docket No. RPU-2023-0002	Clean Energy Districts of Iowa (CEDI) Coalition
May 29, 2024	In Re: Interstate Power & Light Company (General Rate Case) – Surrebuttal Testimony	Iowa Utilities Board Docket No. RPU-2023-0002	Clean Energy Districts of Iowa (CEDI) Coalition

Testimony Submitted by Karl R. Rábago

(as of 8 June 2025)

May 31, 2024	Delta States Utilities LA, LLC and Entergy Louisiana, LLC – Ex Parte; In Re: Application for Authority to Operate as Local Distribution Company and Incur Indebtedness and Joint Application for Approval of Transfer and Acquisition of Local Distribution Company Assets and Related Relief – Direct Testimony	Council of the City of New Orleans Docket Number UD-24-01	Alliance for Affordable Energy
Jun 6, 2024	Tampa Electric Company Petition for Rate Increase – Direct Testimony	Florida Public Service Commission Docket Number 2023-0090-EI	Florida Rising and League of United Latin American Citizens
Jun 11, 2024	Duke Energy Florida Petition for Rate Increase – Direct Testimony	Florida Public Service Commission Docket Number 2024-0025-EI	Florida Rising and League of United Latin American Citizens
Jun 28, 2024	Delta States Utilities LA, LLC and Entergy Louisiana, LLC – Ex Parte; In Re: Application for Authority to Operate as Local Distribution Company and Incur Indebtedness and Joint Application for Approval of Transfer and Acquisition of Local Distribution Company Assets and Related Relief – Rebuttal Testimony	Council of the City of New Orleans Docket Number UD-24-01	Alliance for Affordable Energy
Aug 5, 2024	Delta States Utilities LA, LLC and Entergy Louisiana, LLC – Ex Parte; In Re: Application for Authority to Operate as Local Distribution Company and Incur Indebtedness and Joint Application for Approval of Transfer and Acquisition of Local Distribution Company Assets and Related Relief – Surrebuttal Testimony	Council of the City of New Orleans Docket Number UD-24-01	Alliance for Affordable Energy
Oct 23, 2024	Financial Oversight and Management Board for Puerto Rico as Representative of Puerto Rico Power Authority	U.S. Bankruptcy Court for the District of Puerto Rico, Nos. 17 BK 3283-LTS, BK 4780-LTS	Solar United Neighbors
Jan. 17, 2025	NorthWestern Energy's Application for Authority to Increase Retail Electric and Natural Gas Utility Service Rates	Public Service Commission of Montana Docket Number 2024.05.053	Triple Oak Power, LLC
Nov. 24, 2025	Washington Gas Light Company's Application for Authority to Increase Existing Rates and Charges for Gas Service – Direct Testimony	Public Service Commission of the District of Columbia Formal Case No. 1180	Sierra Club

Testimony Submitted by Karl R. Rábago

(as of 8 June 2025)

Mar. 11, 2025	Petition of Appalachian Power Company for Approval to Revise its Net Metering Program Pursuant to § 56-594 of the Code of Virginia	Virginia State Corporation Commission Case No. PUR-2024-00161	Joint Advocates – Clean Virginia, Sierra Club, Vote Solar, and Solar United Neighbors
Apr. 29, 2025	Investigation of Parallel Generation Purchase Rates	Wisconsin Public Service Commission Docket Number 5-EI-157	City of Madison
May 2, 2025	Washington Gas Light Company's Application for Authority to Increase Existing Rates and Charges for Gas Service – Surrebuttal Testimony	Public Service Commission of the District of Columbia Formal Case No. 1180	Sierra Club
May 12, 2025	In the Matter of Future Minimum Bill Proceedings for Appalachian Power Company pursuant to VA Code § 56-594.4	Virginia State Corporation Commission Case No. PUR-2025-00028	Appalachian Voices
Jun. 4, 2025	Application of El Paso Electric Company for Authority to Change Rates	Public Utility Commission of Texas Docket Number 57568; State Office of Administrative Hearings Docket Number 473-25-11219	Solar Joint Advocates

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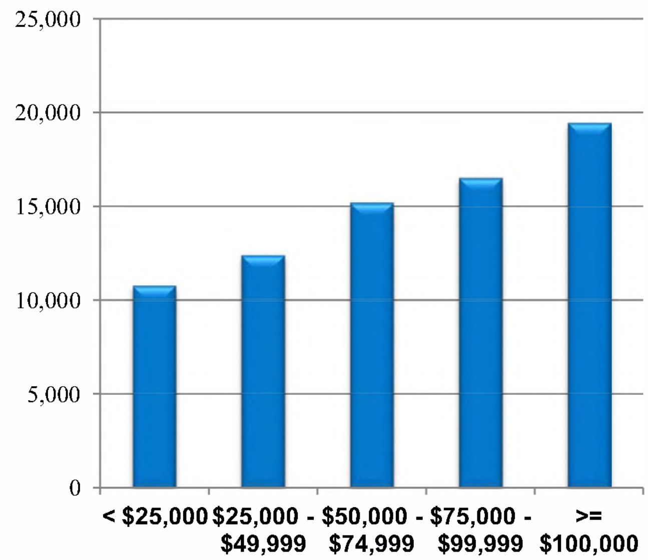
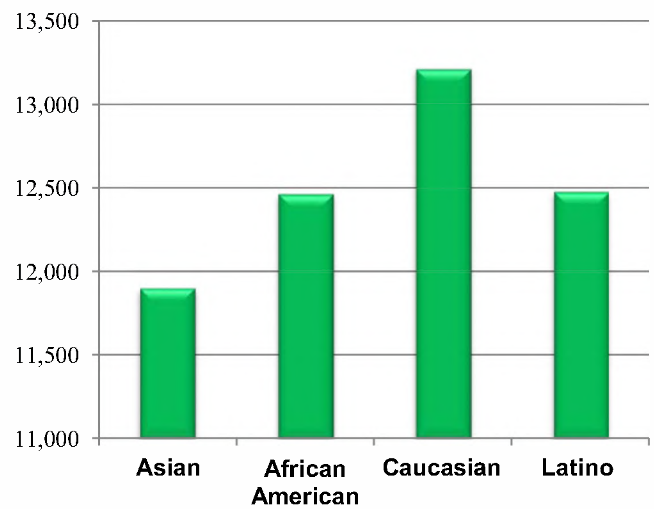
UTILITY RATE DESIGN:
HOW MANDATORY MONTHLY CUSTOMER FEES CAUSE DISPROPORTIONATE HARM

U.S. REGION: FL

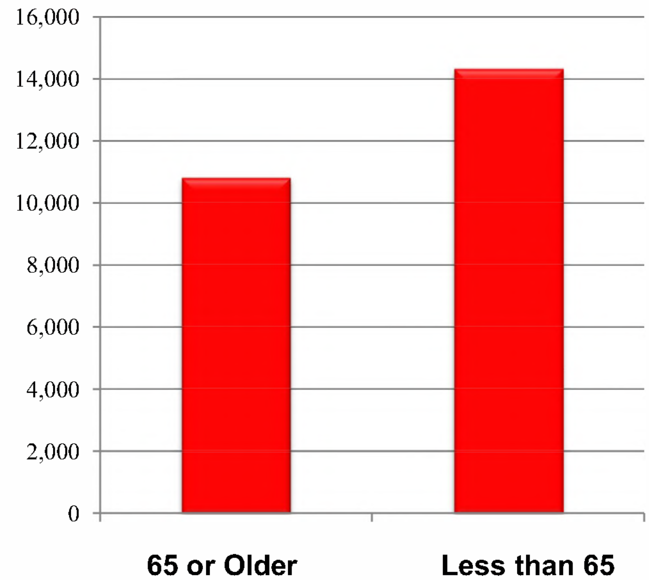
Median 2009 Residential Electricity Usage (KWH), by Income



Median 2009 Residential Electricity Usage (KWH), by Race/Ethnicity



Median 2009 Residential Electricity Usage (KWH), by Age



2009 Residential Energy Consumption by Income, Race/Ethnicity, & Age

HOUSEHOLD INCOME	MEDIAN ELECTRICITY USAGE (KWH)
< $25,000	10,819
$25,000 - $49,999	12,419
$50,000 - $74,999	15,215
$75,000 - $99,999	16,536
>=$100,000	19,467

HOUSEHOLD RACE	MEDIAN ELECTRICITY USAGE (KWH)
Asian	11,905
African American	12,469
Caucasian	13,219
Latino	12,483

HOUSEHOLD AGE	MEDIAN ELECTRICITY USAGE (KWH)
65 years or older	10,834
Less than 65 years	14,346

Source: U.S. Energy Information Administration's Residential Energy Consumption Survey, 2009 (most recent data available)

For questions, contact John Howat: jhowat@nclc.org | 617-542-8010

ATTACHMENT NO. 1

	A	B	C	D	E	F	G	H	I	J	K
1	**Florida Power & Light Company**										
2	**Docket No. 20250011-EI**										
3											
4											
5											
6											
7											
8	MFR E-1 - COST OF SERVICE STUDY										
9	2026 AT PRESENT RATES										
10	($000 WHERE APPLICABLE)										
11											
12	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
13											
14	Line No.	Methodologies: 12CP and Energy/Capacity	Total	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2
15	1	**RATE BASE -**									
16	2	Electric Plant In Service	86,274,360	1,161,931	50,452	492,666	5,797,836	18,308	16,938,062	5,729,806	1,953,906
17	3	Accum Depreciation & Amortization	(17,683,082)	(230,402)	(10,073)	(95,567)	(1,221,161)	(4,206)	(3,370,051)	(1,136,130)	(386,461)
18	4	Net Plant in Service	68,591,278	931,529	40,378	397,098	4,576,675	14,102	13,568,011	4,593,676	1,567,445
19	5	Plant Held For Future Use	1,475,168	20,392	876	10,483	98,767	256	302,271	100,826	34,739
20	6	Construction Work in Progress	2,012,666	28,105	1,206	12,339	134,804	446	397,503	136,554	46,954
21	7	Net Nuclear Fuel	745,109	14,205	574	8,163	49,138	184	170,272	62,731	22,819
22	8	Total Utility Plant	72,824,221	994,232	43,033	428,084	4,859,385	14,988	14,438,057	4,893,787	1,671,957
23	9	Working Capital - Assets	5,812,779	77,739	3,300	36,325	406,779	1,638	1,074,958	369,636	128,725
24	10	Working Capital - Liabilities	(3,507,123)	(46,555)	(1,973)	(21,813)	(245,390)	(977)	(644,740)	(221,442)	(77,157)
25	11	Working Capital - Net	2,305,655	31,184	1,327	14,512	161,389	661	430,219	148,194	51,569
26	12	**Total Rate Base**	75,129,876	1,025,415	44,360	442,596	5,020,773	15,650	14,868,275	5,041,981	1,723,526
27	13										
28	14	**REVENUES -**									
29	15	Sales of Electricity	9,617,453	108,286	5,050	46,915	727,953	2,403	1,726,181	546,455	176,685
30	16	Other Operating Revenues	267,316	2,300	97	751	18,461	38	36,209	11,709	4,046
31	17	**Total Operating Revenues**	9,884,769	110,586	5,147	47,666	746,414	2,441	1,762,390	558,164	180,731
32	18										
33	19	**EXPENSES -**									
34	20	Operating & Maintenance Expense	(1,322,364)	(17,387)	(736)	(8,206)	(93,062)	(379)	(240,126)	(82,493)	(28,785)
35	21	Depreciation Expense	(3,081,922)	(39,052)	(1,718)	(16,888)	(208,790)	(658)	(593,194)	(195,153)	(66,047)
36	22	Taxes Other Than Income Tax	(903,354)	(12,249)	(531)	(5,237)	(60,419)	(189)	(178,076)	(60,322)	(20,598)
37	23	Amortization of Property Losses	(15,639)	(208)	(9)	(105)	(1,084)	(4)	(2,972)	(1,003)	(348)
38	24	Gain or Loss on Sale of Plant	420	5	0		29	0	85	29	9
39	25	**Total Operating Expenses**	(5,322,859)	(68,890)	(2,993)	(30,436)	(363,327)	(1,230)	(1,014,282)	(338,942)	(115,768)
40	26										
41	27	**Net Operating Income Before Taxes**	4,561,910	41,696	2,154	17,230	383,087	1,211	748,107	219,221	64,963
42	28	Income Taxes	18,213	359	14	157	786	2	4,448	1,694	632
43	29	**NOI Before Curtailment Adjustment**	4,580,123	42,055	2,168	17,387	383,873	1,213	752,556	220,915	65,595
44	30										
45	31	Curtailment Credit Revenue	469							329	141
46	32	Reassign Curtailment Credit Revenue	(469)	(7)	(0)	(4)	(31)	(0)	(97)	(32)	(11)

ATTACHMENT NO. 1

	A	B	C	D	E	F	G	H	I	J	K
7											
8	MFR E-1 - COST OF SERVICE STUDY										
9	2026 AT PRESENT RATES										
10	($000 WHERE APPLICABLE)										
11											
12	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
13											
14	Line No.	Methodologies: 12CP and Energy/Capacity	Total	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2
47	33	Net Curtailment Credit Revenue	(0)	(7)	(0)	(4)	(31)	(0)	(97)	297	130
48	34	Net Curtailment NOI Adjustment	(0)	(5)	(0)	(3)	(23)	(0)	(72)	221	97
49	35										
50	36	**Net Operating Income (NOI)**	4,580,123	42,050	2,168	17,384	383,849	1,213	752,484	221,136	65,692
51	37										
52	38	**Rate of Return (ROR)**	6.10%	4.10%	4.89%	3.93%	7.65%	7.75%	5.06%	4.39%	3.81%
53	39										
54	40	**Parity at Present Rates**	1.000	0.673	0.802	0.644	1.254	1.272	0.830	0.719	0.625
55	41										
56	42	**EQUALIZED RATE OF RETURN (ROR) -**									
57	43	Equalized Base Revenue Requirements	9,617,453	128,854	5,590	56,559	649,729	2,142	1,880,880	633,384	216,375
58	44	Other Operating Revenues	267,316	2,300	97	751	18,461	38	36,209	11,709	4,046
59	45	**Total Equalized Revenue Requirements**	9,884,769	131,154	5,687	57,310	668,190	2,180	1,917,089	645,093	220,421
60	46										
61	47	**Revenue Requirements Deficiency (Excess)**	(0)	20,568	539	9,644	(78,224)	(261)	154,699	86,929	39,690
62	48										
63	49	**Revenue Requirements Index** (1)		84.3%	90.5%	83.2%	111.7%	112.0%	91.9%	86.5%	82.0%
64	50										
65	51	(1) Total Revenues divided by Total									
66	52	Equalized Revenue Requirements									
67	53										
68	54	Note: Totals may not add due to rounding.									
69											
70											
71											
72											
73		Equalization Calculation									
74				CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2
75		Eqalized ROR	6.10%								
76		Equalized NOI	4,580,123	62,512	2,704	26,982	306,080	954	906,411	307,373	105,071
77				1.36%	0.06%	0.59%	6.68%	0.02%	19.79%	6.71%	2.29%
78		Income Taxes	18,213	249	11	107	1,217	4	3,604	1,222	418
79		Total Equalized Base Revenue Requirements	9,884,769	131,154	5,687	57,310	668,190	2,180	1,917,089	645,093	220,421

ATTACHMENT NO. 1

	A	B	L	M	N	O	P	Q	R	S	T
1	**Florida Power & Light Company**										
2	**Docket No. 20250011-EI**										
3											
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6											
7											
8	MFR E-1 - COST OF SERVICE STUDY										
9	2026 AT PRESENT RATES										
10	($000 WHERE APPLICABLE)										
11											
12	(1)	(2)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
13											
14	Line No.	Methodologies: 12CP and Energy/Capacity	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST
15	1	**RATE BASE -**									
16	2	Electric Plant In Service	324,083	38,544	26,185	51,938,857	1,726,746	16,532	16,167	4,001	835
17	3	Accum Depreciation & Amortization	(62,672)	(7,927)	(5,043)	(10,907,980)	(229,969)	(3,576)	(3,052)	(977)	(206)
18	4	Net Plant in Service	261,411	30,618	21,142	41,030,877	1,496,777	12,956	13,115	3,025	629
19	5	Plant Held For Future Use	7,014	682	118	896,695	862	83	246	40	3
20	6	Construction Work in Progress	8,057	879	569	1,205,004	38,354	429	397	102	15
21	7	Net Nuclear Fuel	5,240	385	82	407,592	2,696	217	180	37	0
22	8	Total Utility Plant	281,721	32,564	21,912	43,540,169	1,538,688	13,684	13,938	3,204	647
23	9	Working Capital - Assets	23,621	2,464	1,241	3,606,474	74,227	1,253	1,176	424	42
24	10	Working Capital - Liabilities	(14,190)	(1,463)	(718)	(2,184,201)	(43,133)	(740)	(706)	(257)	(23)
25	11	Working Capital - Net	9,432	1,001	523	1,422,272	31,094	513	470	167	19
26	12	**Total Rate Base**	291,153	33,565	22,434	44,962,441	1,569,782	14,197	14,408	3,371	666
27	13										
28	14	**REVENUES -**									
29	15	Sales of Electricity	32,160	4,368	2,031	6,038,411	189,177	1,552	1,851	564	181
30	16	Other Operating Revenues	826	77	102	190,530	2,002	38	46	9	3
31	17	**Total Operating Revenues**	32,986	4,445	2,133	6,228,941	191,179	1,591	1,897	574	184
32	18										
33	19	**EXPENSES -**									
34	20	Operating & Maintenance Expense	(5,334)	(544)	(251)	(828,738)	(15,053)	(280)	(267)	(102)	(8)
35	21	Depreciation Expense	(11,186)	(1,369)	(835)	(1,891,573)	(52,929)	(467)	(540)	(140)	(32)
36	22	Taxes Other Than Income Tax	(3,445)	(402)	(276)	(541,373)	(19,425)	(172)	(173)	(41)	(8)
37	23	Amortization of Property Losses	(69)	(7)	(2)	(9,724)	(89)	(2)	(3)	(1)	(0)
38	24	Gain or Loss on Sale of Plant		0	0	260	2	0	0	0	0
39	25	**Total Operating Expenses**	(20,034)	(2,322)	(1,363)	(3,271,148)	(87,495)	(920)	(983)	(284)	(48)
40	26										
41	27	**Net Operating Income Before Taxes**	12,952	2,123	771	2,957,793	103,684	671	915	290	136
42	28	Income Taxes	94	8	9	9,642	368	5	3	0	(0)
43	29	**NOI Before Curtailment Adjustment**	13,046	2,131	780	2,967,434	104,053	675	918	290	136
44	30										
45	31	Curtailment Credit Revenue									
46	32	Reassign Curtailment Credit Revenue	(2)	(0)	(0)	(285)		(0)	(0)	(0)	(0)

ATTACHMENT NO. 1

	A	B	L	M	N	O	P	Q	R	S	T
7											
8	MFR E-1 - COST OF SERVICE STUDY										
9	2026 AT PRESENT RATES										
10	($000 WHERE APPLICABLE)										
11											
12	(1)	(2)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
13											
14	Line No.	Methodologies: 12CP and Energy/Capacity	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST
47	33	Net Curtailment Credit Revenue	(2)	(0)	(0)	(285)		(0)	(0)	(0)	(0)
48	34	Net Curtailment NOI Adjustment	(2)	(0)	(0)	(212)		(0)	(0)	(0)	(0)
49	35										
50	36	**Net Operating Income (NOI)**	13,044	2,131	780	2,967,222	104,053	675	918	290	136
51	37										
52	38	**Rate of Return (ROR)**	4.48%	6.35%	3.47%	6.60%	6.63%	4.75%	6.37%	8.61%	20.33%
53	39										
54	40	**Parity at Present Rates**	0.735	1.041	0.570	1.083	1.087	0.780	1.045	1.412	3.335
55	41										
56	42	**EQUALIZED RATE OF RETURN (ROR) -**									
57	43	Equalized Base Revenue Requirements	36,887	4,283	2,623	5,810,751	180,810	1,744	1,811	479	86
58	44	Other Operating Revenues	826	77	102	190,530	2,002	38	46	9	3
59	45	**Total Equalized Revenue Requirements**	37,713	4,360	2,725	6,001,281	182,812	1,782	1,857	489	89
60	46										
61	47	**Revenue Requirements Deficiency (Excess)**	4,727	(85)	592	(227,659)	(8,367)	192	(40)	(85)	(95)
62	48										
63	49	**Revenue Requirements Index** [1]	87.5%	102.0%	78.3%	103.8%	104.6%	89.3%	102.1%	117.4%	207.7%
64	50										
65	51	[1] Total Revenues divided by Total									
66	52	Equalized Revenue Requirements									
67	53										
68	54	Note: Totals may not add due to rounding.									
69											
70											
71											
72											
73		Equalization Calculation									
74			GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST
75		Eqalized ROR									
76		Equalized NOI	17,749	2,046	1,368	2,741,034	95,698	866	878	205	41
77			0.39%	0.04%	0.03%	59.85%	2.09%	0.02%	0.02%	0.00%	0.00%
78		Income Taxes	71	8	5	10,900	381	3	3	1	0
79		Total Equalized Base Revenue Requirements	37,713	4,360	2,725	6,001,281	182,812	1,782	1,857	489	89

ATTACHMENT NO. 1

	A	B	U
1	**Florida Power & Light Company**		
2	**Docket No. 20250011-EI**		
3			
4			
5			
6			
7			
8	MFR E-1 - COST OF SERVICE STUDY		
9	2026 AT PRESENT RATES		
10	($000 WHERE APPLICABLE)		
11			
12	(1)	(2)	(21)
13			
14	Line No.	Methodologies: 12CP and Energy/Capacity	SST-TST
15	1	**RATE BASE -**	
16	2	Electric Plant In Service	39,443
17	3	Accum Depreciation & Amortization	(7,629)
18	4	Net Plant in Service	31,813
19	5	Plant Held For Future Use	815
20	6	Construction Work in Progress	948
21	7	Net Nuclear Fuel	593
22	8	Total Utility Plant	34,170
23	9	Working Capital - Assets	2,756
24	10	Working Capital - Liabilities	(1,646)
25	11	Working Capital - Net	1,111
26	12	**Total Rate Base**	35,281
27	13		
28	14	**REVENUES -**	
29	15	Sales of Electricity	7,229
30	16	Other Operating Revenues	72
31	17	**Total Operating Revenues**	7,301
32	18		
33	19	**EXPENSES -**	
34	20	Operating & Maintenance Expense	(616)
35	21	Depreciation Expense	(1,353)
36	22	Taxes Other Than Income Tax	(419)
37	23	Amortization of Property Losses	(8)
38	24	Gain or Loss on Sale of Plant	
39	25	**Total Operating Expenses**	(2,395)
40	26		
41	27	**Net Operating Income Before Taxes**	4,906
42	28	Income Taxes	(7)
43	29	**NOI Before Curtailment Adjustment**	4,899
44	30		
45	31	Curtailment Credit Revenue	
46	32	Reassign Curtailment Credit Revenue	(0)

ATTACHMENT NO. 1

	A	B	U
7			
8	MFR E-1 - COST OF SERVICE STUDY		
9	2026 AT PRESENT RATES		
10	($000 WHERE APPLICABLE)		
11			
12	(1)	(2)	(21)
13			
14	Line No.	Methodologies: 12CP and Energy/Capacity	SST-TST
47	33	Net Curtailment Credit Revenue	(0)
48	34	Net Curtailment NOI Adjustment	(0)
49	35		
50	36	**Net Operating Income (NOI)**	4,899
51	37		
52	38	**Rate of Return (ROR)**	13.89%
53	39		
54	40	**Parity at Present Rates**	2.278
55	41		
56	42	**EQUALIZED RATE OF RETURN (ROR) -**	
57	43	Equalized Base Revenue Requirements	4,466
58	44	Other Operating Revenues	72
59	45	**Total Equalized Revenue Requirements**	4,537
60	46		
61	47	**Revenue Requirements Deficiency (Excess)**	(2,764)
62	48		
63	49	**Revenue Requirements Index** [(1)]	160.9%
64	50		
65	51	[(1)] Total Revenues divided by Total	
66	52	Equalized Revenue Requirements	
67	53		
68	54	Note: Totals may not add due to rounding.	
69			
70			
71			
72			
73		Equalization Calculation	
74			SST-TST
75		Eqalized ROR	
76		Equalized NOI	2,151
77			0.05%
78		Income Taxes	9
79		Total Equalized Base Revenue Requirements	4,537

ATTACHMENT NO. 2

	A	B	C	D	E	F	G	H	I	J	K
1	**Florida Power & Light Company**										
2	**Docket No. 20250011-EI**										
3											
4											
5											
6											
7											
8	MFR E-1 - COST OF SERVICE STUDY										
9	2026 EQUALIZED AT PROPOSED ROR										
10	($000 WHERE APPLICABLE)										
11											
12	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
13											
14	Line No.	Methodologies: 12CP and Energy/Capacity	Total	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2
15	1	**RATE BASE -**									
16	2	Electric Plant In Service	86,274,360	1,161,931	50,452	492,666	5,797,836	18,308	16,938,062	5,729,806	1,953,906
17	3	Accum Depreciation & Amortization	(17,683,082)	(230,402)	(10,073)	(95,567)	(1,221,161)	(4,206)	(3,370,051)	(1,136,130)	(386,461)
18	4	Net Plant in Service	68,591,278	931,529	40,378	397,098	4,576,675	14,102	13,568,011	4,593,676	1,567,445
19	5	Plant Held For Future Use	1,475,168	20,392	876	10,483	98,767	256	302,271	100,826	34,739
20	6	Construction Work in Progress	2,012,666	28,105	1,206	12,339	134,804	446	397,503	136,554	46,954
21	7	Net Nuclear Fuel	745,109	14,205	574	8,163	49,138	184	170,272	62,731	22,819
22	8	Total Utility Plant	72,824,221	994,232	43,033	428,084	4,859,385	14,988	14,438,057	4,893,787	1,671,957
23	9	Working Capital - Assets	5,812,779	77,739	3,300	36,325	406,779	1,638	1,074,958	369,636	128,725
24	10	Working Capital - Liabilities	(3,507,123)	(46,555)	(1,973)	(21,813)	(245,390)	(977)	(644,740)	(221,442)	(77,157)
25	11	Working Capital - Net	2,305,655	31,184	1,327	14,512	161,389	661	430,219	148,194	51,569
26	12	**Total Rate Base**	75,129,876	1,025,415	44,360	442,596	5,020,773	15,650	14,868,275	5,041,981	1,723,526
27	13										
28	14	**TARGET REVENUE REQUIREMENTS (EQUALIZED) -**									
29	15	Equalized Base Revenue Requirements	9,591,421	135,368	5,754	59,631	621,831	2,049	1,927,351	660,333	228,891
30	16	Other Operating Revenues	266,875	2,300	97	751	18,513	40	36,239	11,710	4,046
31	17	**Total Target Revenue Requirements**	9,858,295	137,668	5,851	60,382	640,344	2,088	1,963,590	672,043	232,937
32	18										
33	19	**EXPENSES -**									
34	20	Operating & Maintenance Expense	(1,322,332)	(17,420)	(737)	(8,221)	(92,931)	(379)	(240,374)	(82,634)	(28,849)
35	21	Depreciation Expense	(3,081,922)	(39,052)	(1,718)	(16,888)	(208,790)	(658)	(593,194)	(195,153)	(66,047)
36	22	Taxes Other Than Income Tax	(903,354)	(12,249)	(531)	(5,237)	(60,419)	(189)	(178,076)	(60,322)	(20,598)
37	23	Amortization of Property Losses	(15,639)	(208)	(9)	(105)	(1,084)	(4)	(2,972)	(1,003)	(348)
38	24	Gain or Loss on Sale of Plant	420	5	0		29	0	85	29	9
39	25	**Total Operating Expenses**	(5,322,827)	(68,924)	(2,994)	(30,451)	(363,196)	(1,230)	(1,014,531)	(339,083)	(115,832)
40	26										
41	27	**Net Operating Income Before Taxes**	4,535,469	68,744	2,857	29,930	277,148	858	949,059	332,960	117,105
42	28	Income Taxes	24,915	(6,496)	(165)	(3,062)	27,636	92	(46,483)	(27,133)	(12,583)
43	29	**NOI Before Curtailment Adjustment**	4,560,383	62,248	2,693	26,868	304,784	950	902,576	305,827	104,521
44	30										
45	31	Curtailment Credit Revenue	469							329	141
46	32	Reassign Curtailment Credit Revenue	(469)	(7)	(0)	(4)	(31)	(0)	(97)	(32)	(11)

ATTACHMENT NO. 2

	A	B	C	D	E	F	G	H	I	J	K
7											
8	MFR E-1 - COST OF SERVICE STUDY										
9	2026 EQUALIZED AT PROPOSED ROR										
10	($000 WHERE APPLICABLE)										
11											
12	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
13											
14	Line No.	Methodologies: 12CP and Energy/Capacity	Total	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2
47	33	Net Curtailment Credit Revenue	(0)	(7)	(0)	(4)	(31)	(0)	(97)	297	130
48	34	Net Curtailment NOI Adjustment	(0)	(5)	(0)	(3)	(23)	(0)	(72)	221	97
49	35										
50	36	**Net Operating Income (NOI)**	4,560,383	62,243	2,693	26,866	304,761	950	902,504	306,048	104,618
51	37										
52	38	**Equalized Rate of Return (ROR)**	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%
53	39										
54	40	**TARGET REVENUE REQUIREMENTS DEFICIENCY -**									
55	41	Base Revenue Requirements	(26,033)	27,082	704	12,716	(106,122)	(355)	201,170	113,878	52,205
56	42	Other Operating Revenues	(441)	0	0	0	53	1	30	2	0
57	43	**Target Revenue Requirements Deficiency**	(26,474)	27,082	704	12,716	(106,069)	(353)	201,201	113,880	52,206
58	44										
59	45	**TARGET REVENUE REQUIREMENTS INDEX** (2)									
60	46										
61	47	(1) Target Revenue Requirements at proposed ROR less									
62	48	Total Revenues at present rates from Attachment 1.									
63	49	(2) Total Revenues at present rates from Attachment 1									
64	50	divided by Target Revenue Requirements.									
65	51										
66	52	Note: Totals may not add due to rounding.									
67											
68											
69		**Equalized Revenue Requirement (ASK)**		CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2
70			75,129,876	1,025,415	44,360	442,596	5,020,773	15,650	14,868,275	5,041,981	1,723,526
71		Requested ROR VIA A-1	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%
72		NOI Requested	4,560,383	62,243	2,693	26,866	304,761	950	902,504	306,048	104,618
73		Achieved NOI	4,580,123	42,050	2,168	17,384	383,849	1,213	752,484	221,136	65,692
74		Deficency	(19,739)	20,193	525	9,481	(79,088)	(263)	150,021	84,912	38,926
75		NOI Mulitplier	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
76		Total Requested Increase	(26,474)	27,082	704	12,716	(106,069)	(353)	201,201	113,880	52,206
77											
78											
79											
80				CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2
81		**Tax Calculation**									
82											
83		Achieved		359	14	157	786	2	4,448	1,694	632

ATTACHMENT NO. 2

	A	B	C	D	E	F	G	H	I	J	K
7											
8	MFR E-1 - COST OF SERVICE STUDY										
9	2026 EQUALIZED AT PROPOSED ROR										
10	($000 WHERE APPLICABLE)										
11											
12	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
13											
14	Line No.	Methodologies: 12CP and Energy/Capacity	Total	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2
84											
85		Incremental Total Revenue		27,082	704	12,716	(106,069)	(353)	201,201	113,880	52,206
86		State Rate		5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%
87		Incremental State Taxes		(1,488)	(39)	(699)	5,827	19	(11,052)	(6,256)	(2,868)
88											
89		Federal Rate		19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%
90		Incremental Federal Taxes		(5,368)	(140)	(2,520)	21,023	70	(39,879)	(22,571)	(10,347)
91											
92		Total Taxes	24,915	(6,496)	(165)	(3,062)	27,636	92	(46,483)	(27,133)	(12,583)

ATTACHMENT NO. 2

	A	B	L	M	N	O	P	Q	R	S	T
1	**Florida Power & Light Company**										
2	**Docket No. 20250011-EI**										
3											
4											
5											
6											
7											
8	MFR E-1 - COST OF SERVICE STUDY										
9	2026 EQUALIZED AT PROPOSED ROR										
10	($000 WHERE APPLICABLE)										
11											
12	(1)	(2)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
13											
14	Line No.	Methodologies: 12CP and Energy/Capacity	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST
15	1	**RATE BASE -**									
16	2	Electric Plant In Service	324,083	38,544	26,185	51,938,857	1,726,746	16,532	16,167	4,001	835
17	3	Accum Depreciation & Amortization	(62,672)	(7,927)	(5,043)	(10,907,980)	(229,969)	(3,576)	(3,052)	(977)	(206)
18	4	Net Plant in Service	261,411	30,618	21,142	41,030,877	1,496,777	12,956	13,115	3,025	629
19	5	Plant Held For Future Use	7,014	682	118	896,695	862	83	246	40	3
20	6	Construction Work in Progress	8,057	879	569	1,205,004	38,354	429	397	102	15
21	7	Net Nuclear Fuel	5,240	385	82	407,592	2,696	217	180	37	0
22	8	Total Utility Plant	281,721	32,564	21,912	43,540,169	1,538,688	13,684	13,938	3,204	647
23	9	Working Capital - Assets	23,621	2,464	1,241	3,606,474	74,227	1,253	1,176	424	42
24	10	Working Capital - Liabilities	(14,190)	(1,463)	(718)	(2,184,201)	(43,133)	(740)	(706)	(257)	(23)
25	11	Working Capital - Net	9,432	1,001	523	1,422,272	31,094	513	470	167	19
26	12	**Total Rate Base**	291,153	33,565	22,434	44,962,441	1,569,782	14,197	14,408	3,371	666
27	13										
28	14	**TARGET REVENUE REQUIREMENTS (EQUALIZED) -**									
29	15	Equalized Base Revenue Requirements	38,368	4,243	2,812	5,719,751	177,418	1,803	1,792	442	54
30	16	Other Operating Revenues	827	77	102	189,993	2,003	39	47	17	3
31	17	**Total Target Revenue Requirements**	39,194	4,320	2,914	5,909,744	179,421	1,841	1,839	459	56
32	18										
33	19	**EXPENSES -**									
34	20	Operating & Maintenance Expense	(5,341)	(544)	(252)	(828,343)	(15,038)	(280)	(267)	(101)	(8)
35	21	Depreciation Expense	(11,186)	(1,369)	(835)	(1,891,573)	(52,929)	(467)	(540)	(140)	(32)
36	22	Taxes Other Than Income Tax	(3,445)	(402)	(276)	(541,373)	(19,425)	(172)	(173)	(41)	(8)
37	23	Amortization of Property Losses	(69)	(7)	(2)	(9,724)	(89)	(2)	(3)	(1)	(0)
38	24	Gain or Loss on Sale of Plant		0	0	260	2	0	0	0	0
39	25	**Total Operating Expenses**	(20,042)	(2,322)	(1,364)	(3,270,753)	(87,480)	(920)	(983)	(284)	(48)
40	26										
41	27	**Net Operating Income Before Taxes**	19,152	1,998	1,550	2,638,991	91,941	921	857	175	9
42	28	Income Taxes	(1,477)	39	(189)	90,442	3,345	(59)	18	29	32
43	29	**NOI Before Curtailment Adjustment**	17,675	2,038	1,362	2,729,432	95,286	862	875	205	40
44	30										
45	31	Curtailment Credit Revenue									
46	32	Reassign Curtailment Credit Revenue	(2)	(0)	(0)	(285)		(0)	(0)	(0)	(0)

ATTACHMENT NO. 2

	A	B	L	M	N	O	P	Q	R	S	T
7											
8	MFR E-1 - COST OF SERVICE STUDY										
9	2026 EQUALIZED AT PROPOSED ROR										
10	($000 WHERE APPLICABLE)										
11											
12	(1)	(2)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
13											
14	Line No.	Methodologies: 12CP and Energy/Capacity	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST
47	33	Net Curtailment Credit Revenue	(2)	(0)	(0)	(285)		(0)	(0)	(0)	(0)
48	34	Net Curtailment NOI Adjustment	(2)	(0)	(0)	(212)		(0)	(0)	(0)	(0)
49	35										
50	36	**Net Operating Income (NOI)**	17,673	2,037	1,362	2,729,220	95,286	862	875	205	40
51	37										
52	38	**Equalized Rate of Return (ROR)**	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%
53	39										
54	40	**TARGET REVENUE REQUIREMENTS DEFICIENCY -**									
55	41	Base Revenue Requirements	6,207	(125)	781	(318,659)	(11,758)	250	(59)	(122)	(127)
56	42	Other Operating Revenues	0	0	0	(537)	0	0	1	7	0
57	43	**Target Revenue Requirements Deficiency**	6,208	(125)	781	(319,197)	(11,758)	250	(58)	(115)	(127)
58	44										
59	45	**TARGET REVENUE REQUIREMENTS INDEX** (2)									
60	46										
61	47	(1) Target Revenue Requirements at proposed ROR less									
62	48	Total Revenues at present rates from Attachment 1.									
63	49	(2) Total Revenues at present rates from Attachment 1									
64	50	divided by Target Revenue Requirements.									
65	51										
66	52	Note: Totals may not add due to rounding.									
67											
68											
69		**Equalized Revenue Requirement (ASK)**	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST
70			291,153	33,565	22,434	44,962,441	1,569,782	14,197	14,408	3,371	666
71		Requested ROR VIA A-1	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%	6.07%
72		NOI Requested	17,673	2,037	1,362	2,729,220	95,286	862	875	205	40
73		Achieved NOI	13,044	2,131	780	2,967,222	104,053	675	918	290	136
74		Deficency	4,629	(93)	582	(238,002)	(8,767)	187	(43)	(86)	(95)
75		NOI Mulitplier	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
76		Total Requested Increase	6,208	(125)	781	(319,197)	(11,758)	250	(58)	(115)	(127)
77											
78											
79											
80			GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST
81		**Tax Calculation**									
82											
83		Achieved	94	8	9	9,642	368	5	3	0	(0)

ATTACHMENT NO. 2

	A	B	L	M	N	O	P	Q	R	S	T
7											
8	MFR E-1 - COST OF SERVICE STUDY										
9	2026 EQUALIZED AT PROPOSED ROR										
10	($000 WHERE APPLICABLE)										
11											
12	(1)	(2)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
13											
14	Line No.	Methodologies: 12CP and Energy/Capacity	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST
84											
85		Incremental Total Revenue	6,208	(125)	781	(319,197)	(11,758)	250	(58)	(115)	(127)
86		State Rate	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%
87		Incremental State Taxes	(341)	7	(43)	17,534	646	(14)	3	6	7
88											
89		Federal Rate	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%
90		Incremental Federal Taxes	(1,230)	25	(155)	63,266	2,330	(50)	12	23	25
91											
92		Total Taxes	(1,477)	39	(189)	90,442	3,345	(59)	18	29	32

ATTACHMENT NO. 2

	A	B	U	V
1	**Florida Power & Light Company**			
2	**Docket No. 20250011-EI**			
3				
4				
5				
6				
7				
8	MFR E-1 - COST OF SERVICE STUDY			
9	2026 EQUALIZED AT PROPOSED ROR			
10	($000 WHERE APPLICABLE)			
11				
12	(1)	(2)	(21)	
13				
14	Line No.	Methodologies: 12CP and Energy/Capacity	SST-TST	
15	1	**RATE BASE -**		
16	2	Electric Plant In Service	39,443	
17	3	Accum Depreciation & Amortization	(7,629)	
18	4	Net Plant in Service	31,813	
19	5	Plant Held For Future Use	815	
20	6	Construction Work in Progress	948	
21	7	Net Nuclear Fuel	593	
22	8	Total Utility Plant	34,170	
23	9	Working Capital - Assets	2,756	
24	10	Working Capital - Liabilities	(1,646)	
25	11	Working Capital - Net	1,111	
26	12	**Total Rate Base**	35,281	
27	13			
28	14	**TARGET REVENUE REQUIREMENTS (EQUALIZED)**		
29	15	Equalized Base Revenue Requirements	3,531	
30	16	Other Operating Revenues	72	
31	17	**Total Target Revenue Requirements**	3,603	
32	18			
33	19	**EXPENSES -**		
34	20	Operating & Maintenance Expense	(611)	
35	21	Depreciation Expense	(1,353)	
36	22	Taxes Other Than Income Tax	(419)	
37	23	Amortization of Property Losses	(8)	
38	24	Gain or Loss on Sale of Plant		
39	25	**Total Operating Expenses**	(2,390)	
40	26			
41	27	**Net Operating Income Before Taxes**	1,212	
42	28	Income Taxes	929	
43	29	**NOI Before Curtailment Adjustment**	2,142	
44	30			
45	31	Curtailment Credit Revenue		
46	32	Reassign Curtailment Credit Revenue	(0)	

ATTACHMENT NO. 2

	A	B	U	V
7				
8	MFR E-1 - COST OF SERVICE STUDY			
9	2026 EQUALIZED AT PROPOSED ROR			
10	($000 WHERE APPLICABLE)			
11				
12	(1)	(2)	(21)	
13				
14	Line No.	Methodologies: 12CP and Energy/Capacity	SST-TST	
47	33	Net Curtailment Credit Revenue	(0)	
48	34	Net Curtailment NOI Adjustment	(0)	
49	35			
50	36	**Net Operating Income (NOI)**	2,142	
51	37			
52	38	**Equalized Rate of Return (ROR)**	6.07%	
53	39			
54	40	**TARGET REVENUE REQUIREMENTS DEFICIENCY -**		
55	41	Base Revenue Requirements	(3,698)	
56	42	Other Operating Revenues	0	
57	43	**Target Revenue Requirements Deficiency**	(3,698)	
58	44			
59	45	**TARGET REVENUE REQUIREMENTS INDEX** [2]		
60	46			
61	47	[1] Target Revenue Requirements at proposed ROR less		
62	48	Total Revenues at present rates from Attachment 1.		
63	49	[2] Total Revenues at present rates from Attachment 1		
64	50	divided by Target Revenue Requirements.		
65	51			
66	52	Note: Totals may not add due to rounding.		
67				
68				
69		**Equalized Revenue Requirement (ASK)**	SST-TST	
70			35,281	
71		Requested ROR VIA A-1	6.07%	
72		NOI Requested	2,142	
73		Achieved NOI	4,899	
74		Deficency	(2,757)	
75		NOI Mulitplier	1.34	
76		Total Requested Increase	(3,698)	
77				
78				
79				
80			SST-TST	
81		**Tax Calculation**		
82				
83		Achieved	(7)	

ATTACHMENT NO. 2

	A	B	U	V
7				
8	MFR E-1 - COST OF SERVICE STUDY			
9	2026 EQUALIZED AT PROPOSED ROR			
10	($000 WHERE APPLICABLE)			
11				
12	(1)	(2)	(21)	
13				
14	Line No.	Methodologies: 12CP and Energy/Capacity	SST-TST	
84				
85		Incremental Total Revenue	(3,698)	
86		State Rate	5.493%	
87		Incremental State Taxes	203	
88				
89		Federal Rate	19.820%	
90		Incremental Federal Taxes	733	
91				
92		Total Taxes	929	

Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power

Eliza Martin
Ari Peskoe

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ENVIRONMENTAL & ENERGY LAW PROGRAM
HARVARD LAW SCHOOL

Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power

Eliza Martin and Ari Peskoe*

Executive Summary

Some of the largest companies in the world — including Amazon, Google, Meta, and Microsoft — are looking to secure electricity for their energy-intensive operations.[1] Their quests for power to supply their growing "data centers" are super-charging a growing national market for electricity service that pits regional utilities against each other. In this paper, we investigate one aspect of this competition: how utilities can fund discounts to Big Tech by socializing their costs through electricity prices charged to the public. Hiding subsidies for trillion-dollar companies in power prices increases utility profits by raising costs for American consumers.

Because for-profit utilities enjoy state-granted monopolies over electricity delivery, states must protect the public by closely regulating the prices utilities charge for service. Regulated utility rates reimburse utilities for their costs of providing service and provide an opportunity to profit on their investments in new infrastructure. This age-old formula was designed to motivate utility expansion so it would meet society's growing energy demands.

The sudden surge in electricity use by data centers — warehouses filled with power-hungry computer chips — is shifting utilities' attention away from societal needs and to the wishes of a few energy-intensive consumers. Utilities' narrow focus on expanding to serve a handful of Big Tech companies, and to a lesser extent cryptocurrency speculators, breaks the mold of traditional utility rates that are premised on spreading the costs of beneficial system expansion to all ratepayers. The very same rate structures that have socialized the costs of reliable power delivery are now forcing the public to pay for infrastructure designed to supply a handful of exceedingly wealthy corporations.

To provide data centers with power, utilities must offer rates that attract Big Tech customers and are approved by the state's public utility commission (PUC). Utilities tell PUCs what they want to hear: that the deals for Big Tech isolate data center energy costs from other ratepayers' bills and won't increase consumers' power prices. But verifying this claim is all but impossible. Attributing utility costs to a specific consumer is an imprecise exercise premised on debatable claims about utility accounting records. The subjectivity and complexity of ratemaking conceal utility attempts to funnel revenue to their competitive lines of business by overcharging captive ratepayers. While PUCs are supposed to prevent utilities

from extracting such undue profits from ratepayers, utilities' control over rate-setting processes provides them with opportunities to obscure their self-interested strategies.

Detecting wealth transfers from ratepayers to utility shareholders and Big Tech companies is particularly challenging because utilities ask PUCs for confidential treatment of their contracts with data centers, which limits scrutiny of utilities' proposed deals and narrows the scope of regulators' options when they consider utilities' prices and terms. Meanwhile, regulators face political pressure to approve major economic investments already touted by elected officials for their economic impacts. Rejecting new data center contracts could lead potential Big Tech customers to construct their facilities in other states. Indeed, Big Tech companies have repeatedly told utility regulators that unfavorable utility rates could lead them to invest elsewhere.[2]

In the following sections, we investigate how utilities are shifting the costs of data centers' electricity consumption to other ratepayers. Based on our review of nearly 50 regulatory proceedings about data centers' rates, and the long history of utilities exploiting their monopolies, we are skeptical of utility claims that data center energy costs are isolated from other consumers' bills. After describing the rate mechanisms that shift utility costs among ratepayers, we explain how both existing and new rate structures, as well as secret contracts, could be transferring Big Tech's energy costs to the public. Next, we provide recommendations to limit hidden subsidies in utility rates. Finally, we question whether utility regulators should be making policy decisions about whether to subsidize data centers and speculate on the long-term implications of utility systems dominated by trillion-dollar software and social media companies.

Table of Contents

I. Government-Set Rates Incentivize Utilities to Pursue Data Center Growth at the Expense of the Public

Data centers are large facilities packed with computer servers, networking hardware, and cooling equipment that support services like cloud computing and other data processing applications. While data centers have existed for decades, companies are now building much larger facilities. In 2023, companies began developing facilities that will consume hundreds of megawatts of power, as much as the city of Cleveland.[3] As several companies race to develop artificial intelligence (AI), the scale and energy-intensity of data center development is rapidly accelerating. By the end of 2024, companies started building gigawatt-scale data center campuses and are envisioning even larger facilities that will demand more energy than the nation's largest nuclear power plant could provide.[4]

The sudden and anticipated near-term growth of cloud computing infrastructure to accommodate the development of AI is driving a surge of utility proposals to profit from Big Tech's escalating demands. By 2030, data centers may consume as much as 12 percent of all U.S. electricity and could be largely responsible for *quintupling* the annual growth in electricity demand.[5] This growth is likely to be concentrated in regions with robust access to telecommunications infrastructure and where utilities pledge to quickly meet growing demand. Data centers could substantially expand utilities' size, both financial and physical, as they develop billions of dollars of new infrastructure for Big Tech.[6]

Data center growth is overwhelming long-standing approaches to approving utility rates. Nearly every consumer pays for electricity based on the utilities' average costs of providing service to similar ratepayers. A handful of special interests, particularly large industrial users, pay individualized rates that are negotiated with the utility and often require PUC approval. Data center growth could flip the current ratio of consumers paying general rates to special-interest customers paying unique contracts pursuant to special contracts. In this section, we summarize the potential for massive data center growth and then explore how this growth is challenging long-standing ratemaking practices and is causing the public to subsidize Big Tech's power bills.

A. Utilities Are Projecting Massive Data Center Energy Use

Industry experts and utilities are forecasting massive data center growth, and their projections keep going up. In January 2024, one industry consultancy projected 16 GW of new data center demand by 2030.[7] But by the end of the year, experts were anticipating data center growth to be as high as 65 GW by 2030.[8] Individual utilities are even more bullish. For example, Georgia Power anticipates its total energy sales will nearly double by the early 2030s, a trend it largely attributes to data centers.[9] In Texas, Oncor announced 82 gigawatts of potential data center load,[10] equivalent to the maximum demand of Texas' energy market in 2024.[11] Similarly, AEP, whose multi-state system peaks at 35 GW, expects at least 15 GW of new load from data center customers by 2030,[12] although AEP's Ohio utility added that "customers have expressed interest" in 30 GW of additional data centers in its footprint.[13]

There are reasons, however, to be skeptical of utilities' projections. Utilities have an incentive to provide optimistic projections about potential growth; these announcements are designed in part to grab investors' attention with the promise of new capital spending that will drive future profits.[14] When pressed on their projections, utilities are often reticent to disclose facility-specific details on grounds that a data center's forecasted load is proprietary information.[15] This secrecy can lead utilities and analysts to double-count a data center that requests service from multiple utilities.[16] To acquire power as quickly as possible, data center companies may be negotiating with several utilities to discover which utility can offer service first.

Technological uncertainty further complicates the forecasting challenge. Future innovation may increase or decrease data centers' electricity demand. The current surge in data center growth is traceable to the release of ChatGPT in 2022 and the subsequent burst of AI products and their associated computing needs.[17] Computational or hardware advancements might reduce AI's energy demand and diminish data center demand.[18] For instance, initial reports in January 2025 about the low energy consumption of DeepSeek, a ChatGPT competitor, fueled speculation that more efficient AI models might be just as useful while consuming far less energy. Even if more energy efficient AI models materialize, however, their lower cost could lead consumers to demand more AI services, which could drive power use even higher.[19]

Nonetheless, investment is pouring into data center growth. At a January 21, 2025 White House press conference, OpenAI headlined an announcement of $100 billion in data center investment with the possibility of an additional $400 billion over four years.[20] Earlier that month, Microsoft revealed that it would spend $80 billion on data centers in 2025, including more than $40 billion in the U.S.[21] Two weeks earlier, Amazon said it would spend $10 billion on expanding a data center in Ohio.[22] And two weeks before that, Meta announced its own $10 billion investment to build a new data center in Louisiana.[23]

While the scale and pace of data center growth is impossible to forecast precisely, we know that utilities are projecting and pursuing growth. In the next section, we explore the ratemaking and other regulatory processes that socialize utilities' costs and risks. Unlike companies that face ordinary business risks to their profitability, utilities rely on government regulators to approve their prices and can manipulate rate-setting processes to offer special deals to favored customers that shift the costs of those discounts to the public. This "hidden value transfer," a term coined by Aneil Kovvali and Joshua Macey, is a strategy employed by monopolist utilities to increase profits at the expense of their captive ratepayers.[24] Regulators are supposed to protect against hidden value transfers by aligning rates with the costs utilities incur to serve particular types of consumers. But this rate design strategy is rife with imprecision. In reality, ratepayers are paying for each other's electricity consumption, and data center growth could potentially exacerbate the cross-subsidies that are rampant in utility rates.

B. Utility Rates Socialize Power System Costs Using the "Cost Causation" Standard

The U.S. legal system bestows significant economic advantages on investor-owned utilities (IOUs), which are for-profit companies that enjoy state-granted monopolies to deliver electricity. Government-approved electricity prices reimburse utilities for their operational expenses and provide utilities an opportunity to earn a fixed rate of return on their capital investments. With a monopoly service territory and regulated prices designed to facilitate earnings growth, a utility is insulated from many ordinary business risks and shielded from competitive pressures.

Public utility regulators, or PUCs, must protect the public from a utility's monopoly power and, in the absence of competition, motivate the company to provide reliable and cost-effective service. To meet those goals, PUCs determine whether utility service is offered to all consumers within a utility's service territory at rates and conditions that are "just and reasonable."[25] This standard, enshrined in state law, requires PUCs to balance captive consumers' interests in low prices and fair terms of service against the utility's interest in maximizing returns to its shareholders. A utility rate case is the PUC's primary mechanism for weighing these competing interests by setting equitable prices for consumers that provide for the utilities' financial viability.

"Cost causation" is a guiding principle in ratemaking that dictates consumer prices should align with the costs the utility incurs to provide service to that customer or group of similar ratepayers. By approving rates that roughly meet the cost causation standard, PUCs prevent "undue discrimination" between utility ratepayers, a legal requirement that is typically specified in state law.

While the PUC makes the final decision to approve consumer prices, the utility drives the ratemaking process. In a rate case, the utility's primary goal is to collect enough money to cover its operating expenses and earn a profit on its capital investments. A utility proposes new rates by filing its accounting records and other data and analysis that form the basis of its preferred prices. Once it establishes its "revenue requirement," the utility then proposes to divide this amount among groups of consumers based on their usage patterns, infrastructure requirements, and other characteristics that the utility claims inform its costs of providing service to those consumers. Typical groups, also known as ratepayer classes, include residential, commercial, and industrial consumers. Finally, the utility proposes standardized contracts known as tariffs for each ratepayer class that include uniform charges and terms of service for each member of that ratepayer class.

Under this ratemaking process, residential ratepayers often pay the highest rates because they are distributed across wide areas, often in single-family homes that consume little energy.[26] The utility recovers the costs of building, operating, and maintaining its extensive distribution system to serve residential ratepayers by spreading those costs over the relatively small amount of energy consumed by households. By contrast, an industrial consumer uses far more energy than a household and is likely connected to the power system through higher voltage lines and needs less local infrastructure than residential ratepayers. The utility can distribute lower total infrastructure costs over far greater energy sales to generate a lower industrial rate. Properly designed rates should "produce revenues from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer."[27]

But ratemaking is not "an exact science," and there is not a single correct result.[28] In a utility rate case, various parties advocate for their own self-interest by contesting the utility's filing. Consumer groups and other parties urge the PUC to reduce the utility's revenue requirement, which could potentially lower all rates. But once the revenue requirement is set, consumer groups are pitted against each other as they try to reduce their share of the total amount. Their arguments are based on competing approaches to cost causation, with each party claiming that lower rates for itself align with economic principles, fairness, and other subjective values. Well-resourced participants, such as industrial groups that have a significant incentive to argue for lower power costs, hire lawyers and analysts to comb through the utility's filings and argue that their rates should be lower.

But parties face an uphill battle challenging the utility's accounting records, engineering studies, and other evidence the utility files to justify its preferred rates. Because it initiates the rate case and generates the information needed for the PUC to approve a rate, the utility is inherently advantaged. The information asymmetry between utilities and other parties, as well as the imprecision and subjectivity of the cost causation standard, can facilitate subsidization across classes of ratepayers. We highlight three reasons that PUCs may purposefully or unwittingly approve rates that depart from the cost causation standard.

First, attributing the utilities' costs to various ratepayer classes depends on contested assumptions and disputed methodologies. Different approaches to cost allocation will yield different results. As a pioneer in public utility economics once explained, there are "notorious disagreements among the experts as to the choice of the most rational method of [ ] cost allocation — a disagreement which seems to defy resolution because of the absence of any objective standard of rationality."[29] Parties, including the utility, provide the PUC with competing analyses that are designed to meet their own objectives. For instance, industrial consumers will sponsor a study that concludes lower rates for the industrial rate class is consistent with the cost causation principle. Other parties favor their own interests in what can be a zero-sum game over how to divide the utility's revenue requirement.

Second, the PUC may have its own preferences. In most states, utility commissioners are appointed by the governor, but in ten states they are elected officials. Either commissioner may face political pressure to favor a particular ratepayer class. For instance, an elected commissioner may be inclined to provide lower rates to residential ratepayers who will vote on the commissioner's reelection. An appointed commissioner may choose to align utility rates with a governor's economic development agenda by providing lower rates to major employers, such as the commercial or industrial class. Other pressures may bias regulators in favor of other interests. As it weighs competing evidence about cost allocation provided by various parties in a rate case, the PUC has discretion to find a particular study more credible and may choose a rate structure that aligns with the sponsoring party's goals and the PUC's own preferences. While other parties may challenge a PUC's decision in court, courts are unlikely to overturn a PUC's judgment about cost allocation.[30]

Third, the utility may exploit its informational advantages and intentionally provide false information. A rate case is premised on detailed accounting records filed by the utility about the expenses it incurs to provide service. The spreadsheets and other information that the utility files are based on internal records not available to the PUC or rate-case parties. Even if the utility provides some of its records in response to a party's request, the information might be too voluminous for the PUC or other parties to verify. Ultimately, the PUC relies on the utility's good faith. However, recent cases show that utilities are filing fabricated or misleading records.[31]

A random audit of multi-state utility company FirstEnergy by the Federal Energy Regulatory Commission (FERC) found that the utility had hidden lobbying expenses tied to political corruption by mislabeling them as legitimate expenses in its accounting books. According to the audit, the utility's internal controls had been "possibly obfuscated or circumvented to conceal or mislead as to the actual amounts, nature and purpose of the lobbying expenditures."[32] The audit concluded that the utility's mislabeling allowed the inappropriate lobbying expenses to be included in rates.[33] Rate cases did not detect this deception. Only an audit, informed by an extensive federal sting operation, revealed the utility's deceit. Regulators have recently uncovered other utilities filing false or misleading information in regulated proceedings.[34]

Once the regulators approve utility rates, some consumers can shift costs to other ratepayers by fine-tuning their energy consumption. As we discuss in more detail in part II.B.3, rates for commercial and industrial ratepayers typically include demand charges that are tied to each consumer's energy consumption during the utility's or regional power system's moment of peak demand that year. By anticipating when that peak will happen and reducing consumption of utility-delivered power at that moment, a data center or other energy-intensive consumer can substantially reduce its bill. While this "peak shaving" can reduce power prices for other consumers, it also forces other ratepayers to pay part of the energy-intensive consumer's share of infrastructure costs.

Despite its flaws, ratemaking continues to be the dominant approach to financing power sector infrastructure. Uniform, stable prices provide predictable revenue that motivates investors to fund utility expansion. Rate regulation typically insulates investors from many ordinary business risks by putting ratepayers on the hook for the company's engineering, construction, or procurement mistakes. For instance, regulators often allow utilities to increase rates when their projects are over-budget. The utility rarely faces financial consequences for missteps that would cause businesses that rely on competitive markets to lose profits.

Some energy-intensive consumers can be exempted from this ratemaking process that socializes costs and shifts risks to the public. The special rates for these consumers are set in one-off agreements that can lock in long-term prices and shield it from risks faced by other ratepayers. These contracts, which typically require PUC approval, allow an individual consumer to take service under conditions and terms not otherwise available to anyone else. Special rates are, in essence, "a discriminatory action, but one that regulators can justify under certain conditions."[35]

To protect ratepayers, some state laws authorizing special contracts require PUCs to evaluate whether the contract meets the cost causation standard.[36] However, the "notorious disagreements" about how to measure whether a consumer is paying for its costs of service still plague the special-contract cost causation analysis. And, as we describe below, proceedings about special contracts present unique obstacles to evaluating cost causation.

In other states, however, laws authorizing special contracts do not prevent PUCs from approving below-cost contracts. For instance, Kansas law allows regulators to approve special rates if it determines that the rate is in the state's best interest based on multiple factors, including economic development, local employment, and tax revenues.[37] A recent law enacted in Mississippi strips utility regulators of any authority to review contracts between a utility and a data center.[38]

Regardless of the standard for reviewing special contracts, there is significant political pressure on regulators to approve these deals, even if such development results in higher electricity costs for other ratepayers. Regulators do not want to be seen as the veto point for an economic development opportunity, which may have already been publicized by the company and the governor. Because utilities may be competing for the profitable opportunity to serve a particular energy-intensive consumer, they have an incentive to offer low prices, even if that reduced rate results in higher costs for the utility's other ratepayers. As noted, despite their wealth, Big Tech companies seek low energy prices and make siting decisions based in part on price.[39] Regulatory scrutiny of special contracts is therefore a critical backstop for protecting ratepayers.

II. How Data Center Costs Creep into Ratepayers' Bills

When a utility expands its system in anticipation of growing consumer demand, it typically seeks to include the capital costs of new infrastructure in its rates. If approved, ratepayers share the costs of the utility's expansion pursuant to a cost allocation formula accepted by the PUC. This approach, while imperfect for the reasons described in the previous section, has facilitated population growth and economic development by forcing ratepayers to subsidize new infrastructure that will allow new residents and businesses to receive utility-delivered energy.

For many utilities, their expectations about growth are now dominated by new data centers. Rather than being dispersed across a utility's service territory like homes and businesses, these new data center consumers that are benefitting from utility expansion are identifiable and capable of paying for infrastructure that will directly serve their facilities. If PUCs allow utilities to follow the conventional approach of socializing system expansion, utilities will impose data centers' energy costs on the public. The easiest way for utilities to shift data centers' energy costs to the public is to simply follow long-standing practices in rate cases.

In our view, however, utilities are often using more subtle ratemaking methods to push data centers' energy costs onto consumers' bills.

In this section, we focus on three mechanisms that can force consumers to pay for data center's energy costs. First, special contracts between utilities and data centers, approved through opaque regulatory processes, are transferring data center costs to other consumers. Second, disconnected processes for setting federally regulated transmission and wholesale power rates and state-set consumer prices are: A) causing consumers to pay for interstate infrastructure needed to accommodate new data centers; B) putting consumers on the hook for new infrastructure built for data-center load that never materializes; and C) allowing data centers to strategically reduce energy usage during a few hours to reduce their bills and shift costs to other consumers. Third, data centers that bypass traditional utility ratemaking by contracting directly with power generators may also be raising electricity prices for the public. These co-location agreements between a data center and adjacent non-utility generator may trigger an increase in power market prices and distort regulated electricity delivery rates.

A. Shifting Costs through Secret Contracts

Special contracts are offered by utilities to energy-intensive consumers to attract their business. While regulators in many states are required to protect the public from such cutthroat practices that harm ratepayers, we explain in this section why we are skeptical about utility claims that special contracts for data centers do not force the public to pay for Big Tech's energy costs.

Our review of 40 state PUC proceedings about special contracts with data centers finds that regulators frequently approve special contracts in short and conclusory orders. While PUC rate case decisions are lengthy documents that engage with the evidence filed by the utilities and other parties, most PUC orders approving special contracts provide only cursory analysis of the utility's proposal. One challenge for PUCs is that few, if any, parties participate in these proceedings. As a result, the PUC has little or no evidence in the record to compete with the utility's claim that the contract isolates data center energy costs from other ratepayers' bills.

The PUC often deters parties from arguing against the utility's proposed special contract by reflexively granting utility requests to shield its proposal from public view.[40] The PUC's own grant of confidentiality adds a procedural barrier to greater participation and prevents the public from even attempting to calculate the potential costs of these deals.[41] But perhaps the greater impediment to third-party analysis of proposed special contracts is that ratepayers believe that they have little at stake in the proceedings. Unlike rate cases, which set the prices consumers pay, a special contract will only have indirect financial effects on other ratepayers if it shifts costs that the energy-intensive customer ought to pay on to other ratepayers' bills. Because meaningfully participating in a special contract case has a high cost and a generally low reward, otherwise interested parties have typically not bothered to contest them. But the scale of data center special contracts demands attention because the costs being shifted to the public could be staggering.

A special contract shifts costs to other ratepayers when the customer pays the utility a price lower than the utility's costs to serve that customer. To cover the shortfall, utilities will attempt to raise rates for other ratepayers in a subsequent rate case.[42] The amount of the shortfall, and whether there is any shortfall at all, depends on how the utility calculates its costs of providing service to the data center. As discussed above, there are "notorious disagreements" about appropriate methodologies, and even the term "cost" can itself be subject to dispute. Experts debate, for instance, when to use average or marginal costs and whether short- or long-term costs are suitable metrics. When utilities use one metric in a rate case and another metric in a special contract proceeding, they could be causing spillover effects that harm ratepayers.[43]

The disagreements about methodologies and complexities of the calculations underscore a foundational challenge to reviewing a special contract rate. As discussed above, PUC rate case decisions do not purport to assign utility costs to individual consumers but instead apportion cost responsibility among similar ratepayers grouped together as classes. But in a special contract proceeding, the utility makes the unusual claim that it can isolate its costs to serve a single consumer. Without contrary evidence filed by interested parties, the PUC may have little basis for rejecting the utility's analysis.

Even without the benefit of third-party analyses in special contract proceedings, PUC orders may summarize cross-subsidy concerns raised by their own staff. But challenging the utility's analysis is costly and time-intensive, and staff may not have the resources to provide robust analysis. Similarly, state ratepayer advocates occasionally participate in these proceedings and raise cross subsidy arguments, but they are also often stretched too thin to provide a detailed response to the utility's proposal. As a result, we find that many PUC orders approving special contracts simply conclude that the proposed contract is reasonable without meaningfully engaging with the proposal.[44]

Such PUC orders are therefore not persuasive in assuaging concerns that the public may be subsidizing Big Tech's energy costs. Moreover, as discussed, state regulators may face political pressure not to veto a significant construction project in the state. The utility's assertion that it is protecting other ratepayers may provide enough cover for regulators to approve a special contract. The obscurity and complexity of these proceedings provides utilities with opportunities to hide data center energy costs and force them onto other consumers' bills.

Recent litigation against Duke Energy, one of the largest utilities in the country, exposed that the company was acting on its incentive to shift costs of a special contract to its other ratepayers. Duke's scheme responded to a new power plant developer offering competitive contracts to supply small non-profit utilities that had been purchasing power from Duke.[45] Duke's internal documents disclosed through litigation revealed that the new company was far more efficient than Duke and the utility therefore could not compete for customers based on price. Nonetheless, Duke offered one of its larger customers a new contract that amounted to a $325 million discount compared to its existing deal with Duke.[46] Additional internal utility documents revealed that Duke developed a plan to "shift the cost of the discount" to its other ratepayers by raising their rates.[47] Duke's strategy to force its ratepayers to subsidize the special-contract customer's energy was discovered only because the power plant developer sued Duke in federal court under antitrust law.

While our paper focuses on how consumers are likely subsidizing Big Tech's energy costs through their utility rates, we acknowledge that the reverse is also theoretically possible. A data center taking service under special contracts could be *overpaying*. A utility proposing a special contract might prefer to overcharge one deep-pocketed customer through a special contract in order to reduce rates for the public. While this pricing strategy may seem politically attractive for the utility and PUC, it seems unlikely to attract new data centers.

Regardless of a utility's motivation, regulators are supposed to be skeptical of a sudden surge in utility spending. Superficial reviews of special contracts are insufficient when they are collectively committing utilities to billions of dollars for Big Tech customers. The recent Duke litigation illustrates how utilities take advantage of their monopolies to force ratepayers into subsidizing their competitive lines of businesses. Discounted rates can give a utility an edge in the data center market,[48] and hiding the costs of discounts in ratepayers' bills boosts utility profits. To prevent utilities from overcharging captive ratepayers for the benefit of their competitive businesses, both PUCs and FERC have developed regulatory mechanisms that attempt to prevent such subsidies.[49] For instance, FERC applies special scrutiny to contracts between utilities and power plants that are owned by the same corporate parent. FERC's concern is that because state regulators must let the utility recover its FERC-regulated costs in consumer's rates, "such sales could be made at a rate that is too high, which would give an undue profit to the affiliated [power plant] at the expense of the franchised public utility's captive customers."[50]

Special contracts with data centers are the latest iteration of a long-standing problem with monopolist utilities. Policing cost-shifts in this context is particularly challenging due to the opaque nature of the proceedings, the complexity and subjectivity of assessing the utility's costs of serving an a single consumer, and political pressure on PUCs to approve contracts.

B. Shifting Costs through the Gap Between Federal and State Regulation

When a PUC approves a utility's revenue requirement, it must allow the utility to include interstate transmission and wholesale power market costs that are regulated by FERC.[51] In much of the country, utilities procure power through markets administered by non-profit corporations called Regional Transmission Organizations (RTOs). Market prices are influenced by a host of factors, such as fuel and technology costs, and ultimately reflect generation supply and consumer demand. If supply is constrained by a data center demand surge, market prices would likely increase, at least in the short term. Consumers' utility bills will include these higher power market prices.

PUCs can protect ratepayers from market price increases by allocating the costs of higher prices to data centers. But PUCs rarely order utilities to adjust the formulae that spread FERC-regulated market and transmission costs to ratepayers. In this section, we illustrate how ratepayers can pay more for power due to data center demand by focusing on FERC-regulated transmission costs. Federal law provides FERC with exclusive authority to set utilities' transmission revenue requirements and allocate a utility's transmission revenue requirement to multiple utilities. Under FERC's rules, costs of a new transmission line can be paid entirely by a single utility or shared among utilities if there is agreement that the new line benefits multiple utilities. When costs are shared, a region-specific formula approved by FERC divides costs roughly in proportion to the power system benefits each utility receives, such as lower market prices and improved reliability.[52]

Under either the single-utility or multi-utility approach, PUCs apply their own formula for dividing FERC-allocated transmission costs among ratepayer classes. These separate cost allocation schemes can allow data center energy costs to creep into other consumers' bills when new data centers trigger a need for transmission upgrades. We illustrate by discussing examples of each type of transmission cost recovery and then explain how rate designs embedded in special contracts or tariffs can allow data centers to reduce their bills at the expense of ratepayers.

1. *Separate Federal and PUC Transmission Cost Allocation Methods Allow Data Center Infrastructure Costs to Infiltrate Ratepayers' Bills*

In December 2023, the PJM RTO, a utility alliance stretching from New Jersey to Chicago and south to North Carolina, approved $5 billion of transmission projects whose costs would be shared based among PJM's utility members.[53] PJM identified two factors driving the need for this transmission expansion: retirement of existing generation resources and "unprecedented data center load growth," primarily in Virginia.[54] Pursuant to its FERC-approved cost allocation method, PJM split half of the transmission costs across its footprint based on each utilities' share of regional power demand and allocated the remaining half using a computer simulation of the regional transmission network that estimates benefits each utility receives from the new transmission projects.[55] Under this approach, PJM assigned approximately half of the total cost to Virginia utilities, approximately 10% to Maryland utilities, and the remainder to utilities across the region.[56]

Each state's PUC then allocates the costs assigned by PJM to ratepayer classes of each utility it regulates. In Maryland, across the state's three IOUs assign, an average of 66 percent of transmission costs are assigned to residential ratepayers.[57] The larger of Virginia's two IOUs includes more than half of its transmission costs in residential rates.[58] Thus, in both states, residential ratepayers are paying the majority of regional transmission costs that are tied to data center growth. From the public's perspective, this result appears to violate the cost causation principle. After all, residential ratepayers are not causing PJM to plan new transmission.

PJM's approach, however, recognizes that new regional transmission benefits all ratepayers by improving reliability, allowing for more efficient delivery of power, and providing other power system improvements that are broadly shared. PJM developed its cost-sharing approach with the understanding that new transmission would be designed primarily to provide public benefits. New transmission designed for a few energy-intensive consumers, and not broad public benefits, is inconsistent with PJM's premise. That said, by increasing transmission capacity, new regional transmission lines for data centers may provide ancillary benefits to all ratepayers. PJM's power system simulation, which it uses to allocate half the costs of transmission expansion, demonstrates the shared benefits of this new infrastructure. Proponents of transmission expansion argue that such power flow models validate the current approach of allocating transmission costs to benefiting ratepayers because the models can calculate with reasonable accuracy who benefits from new transmission and therefore who should pay for it.

But even assuming that ancillary benefits for all ratepayers are adequate to justify current methods for regional transmission cost allocation, PJM only spreads costs among the region's utilities. Each utility then has its own methods, approved by PUCs, for allocating transmission investment to its ratepayers. The PUC-approved methods typically presume that ratepayers share in the benefits of new transmission in proportion to their total energy consumption. This approach causes residential ratepayers in Maryland, which consume more than half of the state's electricity, to pay for the lion's share of Maryland utilities' costs of new PJM-planned transmission. Without reforms, consumers will be paying billions of dollars for regional infrastructure that is designed to address the needs of just a few of the world's wealthiest corporations.[59]

Obsolete PUC cost allocation formulas can also cause ratepayers to pay for transmission costs that are not regionally shared. For instance, in July 2024, Virginia's largest utility applied to the PUC for permission to build infrastructure that would serve a new large data center. PUC staff reviewing the proposal found that but for the data center's request, the project "likely, if not certainly, would not be needed at this time."[60] In its application, the utility told state regulators that the $23 million project would be paid for through its FERC-approved transmission tariff.[61] Under the utility's existing state-approved tariff, about half of all costs assigned through the FERC-regulated tariff are billed to residential ratepayers, and the remaining half are billed to other existing ratepayers.[62] The bottom line is that existing tariffs force the public to foot the bill for the data center's transmission.

2. *Utilities May Be Saddling Ratepayers with Stranded Costs for Unneeded Transmission*

If a utility's data center growth projections fail to materialize, ratepayers could be left paying for transmission that the utility constructed in anticipation of data center development. Claiming that it was addressing this "stranded cost" issue, American Electric Power (AEP) of Ohio proposed a new state-regulated tariff that that would require data center customers to enter into long-term contracts with the utility before receiving service. AEP's proposed contract would require the data center to pay 90 percent of costs associated with its maximum demand for a ten-year period, including FERC-regulated transmission costs.[63] According to the utility, this upfront guarantee protects AEP's other ratepayers from the risk that the utility builds new infrastructure for a data center that never materializes and prevents the utility from offloading all of these "stranded" costs on other ratepayers.

While these long-term contracts would at least partially insulate AEP's ratepayers from data center transmission costs, neighboring utilities pointed out that they could still be left paying for stranded costs through PJM's allocation of transmission investments. Their protests explain that if AEP builds new transmission lines in anticipation of data center load growth, and those lines are paid for via PJM's regional cost allocation, then those costs would be split among all PJM-member utilities. As noted, PJM allocates half the costs of new transmission lines to its utility members based on their share of regional energy sales. If AEP's data center customers commence operations, AEP's own share of regional transmission costs would increase in proportion to its rising share of regional energy sales. In that scenario, other utilities in the region may not overpay for transmission needed for AEP's data center customers.

Protesting utilities in the Ohio PUC proceeding focus on the possibility that AEP's data center customers cancel their projects or consume less energy than anticipated after AEP has spent money developing new transmission to meet projected data center demand.[64] Under that scenario, total regional transmission costs would rise due to AEP's spending, but AEP's share of total costs would not increase proportionally. As a result, other regional utilities would face increasing costs to pay for infrastructure developed to meet AEP's unrealized data center energy demand. How much individual consumers pay for the new infrastructure would depend on how each utility allocates transmission costs to various ratepayer classes pursuant to a PUC rate case decision.

New transmission projects paid for by a single utility can also raise stranded cost concerns. In December 2024, FERC approved a contract that governed the construction of transmission facilities needed to provide service to a new data center.[65] Under the contract, the data center will immediately pay for new infrastructure needed to connect the facility to the existing transmission network but will not directly pay for necessary upgrades to existing transmission facilities. Instead, the utility AES pledged to include those upgrade costs in the transmission rates paid by all ratepayers through a subsequent regulatory process. A separate state-regulated tariff for energy-intensive consumers would require the data center, and not other consumers, to ultimately pay for the upgrades. In addition, the contract requires the data center to pay for the upgrades in the event it does not commence operations or uses less energy than would be required under the state-regulated tariff to pay for the upgrades over the time. Our understanding is that this approach to transmission cost recovery for new energy-intensive consumers is fairly common and not limited to data centers, but ratepayer advocates are concerned that data centers' commitments may be more uncertain than other types of energy-intensive consumers.

The Ohio ratepayer advocate therefore protested the contract, arguing that the language protecting other consumers from paying for the transmission upgrades was "unacceptably ambiguous."[66] The Ohio advocate urged FERC to require "specific language to preclude shifting data center costs" to other consumers.[67] FERC nonetheless approved the contract because it found that these concerns were premature and noted that they may be raised in future proceedings that directly address any proposed cost shifts.[68] In a short concurrence, FERC Commissioner Mark Christie questioned whether the rate treatment proposed by the utility that could burden consumers with stranded costs is justified.

3. *By Slightly Reducing Their Energy Use, Data Centers Can Increase Ratepayers' Transmission and Wholesale Market Charges*

Like other ratepayers, data centers pay an energy price for each unit of energy they consume as well as a monthly flat fee. Data centers, and many non-residential ratepayers, also face utility-imposed demand charges that are tied to their peak consumption during a specified month, year, or other time period. These charges are intended to reflect the costs of building power systems that have sufficient capacity to generate and deliver energy when consumer demand is unusually high. In RTO regions, PUC-regulated data center special contracts and tariffs likely reflect FERC-approved demand charges that incorporate regional transmission costs and may also include costs of procuring sufficient power plant capacity to meet peak demand. By reducing their energy use during just a few hours of the year, data centers may be able to reduce their share of regional costs that are allocated to demand charges and effectively force other ratepayers to pick up the tab.

Electricity use is constantly changing, and it peaks when consumers ramp up cooling and heating systems during exceptionally hot or cold days. Meeting these moments of peak demand is very expensive. Consumers pay for transmission and power plant infrastructure that is mostly unused but nonetheless necessary for providing power during a few peak hours each year. While utilities have employed several methods for assessing demand charges, many energy-intensive consumers are billed based on their own consumption at the moment the regional system reaches its peak demand.[69]

Data centers and other large energy users have significant incentives to forecast when this peak hour will occur and reduce their consumption of utility-delivered power during that hour. To avoid shutting down or reducing their production during hours when the system might hit its peak, energy-intensive consumers may install backup generators that displace utility-provided power. Large power users may already have their own power generators to protect against outages or improve the quality of utility-delivered power.[70] Needless to say, most consumers that face demand charges, such as small businesses, do not have a sufficient incentive to forecast the system peaks or install on-site generation. As data centers' share of regional energy consumption grows, Big Tech will be able to shift an increasingly large share of the region's costs to other ratepayers, particularly if their demand charges are easily manipulable.

PUCs can often prevent these cost shifts among consumers who take service from rate-regulated utilities in their states. Federal law requires only that the total costs allocated through FERC-approved tariffs must be passed on to utilities and then ultimately to consumers through PUC-regulated tariffs or special contracts. PUCs can choose their own methods for allocating those costs among ratepayers. Because data centers' special contracts are confidential, we often do not know whether utilities and PUCs are facilitating cost shifts through demand charges. Whether data centers are taking service under tariffs or special contracts, PUCs should ensure that rate structures are not allowing data centers to shift costs through manipulable demand charges.

That said, as we discuss below in part III.E, cutting peak consumption can reduce costs for everyone if utilities build their systems for a lower peak that accounts for a data center's ability to turn off or self-power. The problem is that utilities are expanding based on an assumption that data centers will operate at full power with utility-delivered power during peak periods. When a data center uses its own generation during peak periods to avoid demand charges, it is shifting the costs of an overbuilt system to the public.

C. Shifting Costs by "Co-Locating" Data Centers and Existing Power Plants

Power plant owners have developed their own scheme for attracting data centers that could shift energy costs from data centers to ratepayers. Under "co-location" arrangements, a data center connects directly to an existing power plant behind the plant's point of interconnection to the utility-owned transmission network. By delivering and taking power without using the transmission network, power plant owners and data centers argue that they ought to be exempt from paying utility-assessed energy delivery fees. Utilities have contested this arrangement because it denies them profitable opportunities to build new infrastructure to connect data centers to their networks.

In their haste to secure power as quickly as possible, data centers are looking to contract with existing generation, particularly nuclear power plants. By connecting directly to a power plant, data centers aim to avoid a potentially lengthy process administered by a utility to connect the data center to the utility's power delivery system. Locating load behind a power plant's point of delivery to the transmission network is not new. But the potential scale of data center growth and possibility that some significant share of that growth will co-locate has spawned disputes between power plant owners and utilities.

We highlight the key points about co-location by focusing on regulatory proceedings that involve Constellation, the largest owner of nuclear plants in the U.S., and Exelon, the largest utility in the U.S. that owns only delivery infrastructure and not power plants. Until 2022, Constellation and Exelon were housed under the same corporate parent. The company's restructuring into separate generation and delivery companies allows each of those businesses to independently pursue policies that best meet their financial interests. Data center growth began to rapidly escalate shortly thereafter and has revealed tensions between utilities and companies that compete in wholesale electricity markets for profits.

Co-location is a vague term. Because financial consequences will follow from any regulatory definition of co-location, utilities and power generators dispute how co-location technically functions. Constellation claims that because a data center co-located with one of its nuclear plants cannot receive power from the grid, it is therefore "fully isolated" from the transmission network.[71] Exelon counters that "as a matter of physics and engineering," the co-located data center is "fully integrated with the electric grid."[72] Utilities and other parties point out that a nuclear plant must operate in sync with the other plants connected to the transmission network and claim that the data center benefits from this arrangement even if the transmission system is not delivering power to it.[73]

This technical distinction could affect whether co-located entities are utility ratepayers that pay for delivery service. Constellation argues that because the utility is not delivering energy to the data center, the data center is not a utility customer, and it should not have to pay any FERC- or PUC-regulated delivery charges. Exelon opposes that result and has estimated that a single proposed co-location arrangement between a nuclear owner and a data center would shift between $58 million and $140 million of transmission and state-regulated distribution charges to other ratepayers.[74]

But Constellation and other generators dispute that calculation, claiming that this "phantom . . . 'cost shift' is, at best, merely a back-of-the-envelope estimate" of the revenue a utility would collect if the data center signed up as its customer.[75] Co-location, according to the nuclear plant owners, does not actually cause other ratepayers to pay higher transmission rates but instead precludes them from receiving lower delivery rates that they might pay when a new energy-intensive customer becomes a utility ratepayer and pays its proportional share of the utility's cost of service (a hypothetical that likely does not occur when the new customer receives a one-off price pursuant to a special contract).

But analysts are concerned that co-location can actually raise prices in interstate power markets. Across much of the country, generators are constantly competing through auction markets to supply power. In a few regions, market operators conduct separate annual, monthly, or seasonal auctions for capacity to procure sufficient resources for meeting peak consumer demand. Each power plant can offer capacity into the auction equivalent to its maximum potential for energy generation. In the PJM region, nuclear plants accounted for 21 percent of total capacity that cleared the most recent auction.[76]

PJM's independent market monitor, who fiercely promotes and defends PJM's markets, recently warned that colocation could "undermine" PJM's markets. He posited that if all nuclear plants in the region attracted co-located customers, "the impact on the PJM grid and markets would be extreme. Power flows on the grid that was built in significant part to deliver low-cost nuclear energy to load would change significantly. Energy prices would increase significantly as low-cost nuclear energy is displaced by higher cost energy . . . Capacity prices would increase as the supply of capacity to the market is reduced."[77] Should this scenario play out, the region's ratepayers could be forced to pay higher prices due to data centers' purchasing decisions. However, as noted, steep increases in demand due to data center growth could increase wholesale market prices regardless of whether data centers co-locate with existing power plants.

For utilities, opposing co-location is not purely about protecting their ratepayers or upholding the integrity of interstate markets. Co-location threatens their control over power delivery by allowing data centers to take energy directly from a large power producer. In some states, utilities might claim that state laws prohibit co-location because they provide the utility with a monopoly on retail sales.[78] Co-location would also reduce the profits that utilities would otherwise stand to gain from constructing new infrastructure to serve data centers.

In an ongoing FERC proceeding, Constellation claims that utilities' opposition to co-location is an anti-competitive ploy to capitalize on their state-granted monopolies.[79] The company alleges that co-location arrangements at two of its nuclear plants are "being held hostage by one or two monopoly utilities . . . [that] have taken the law into their own hands, and are unilaterally blocking co-location projects unless the future data center customers accede to utility demands to take [ ] transmission services . . . from the utility and sign up for retail distribution services."[80] Utilities may be trying to delay Constellation's projects until FERC provides clear guidance on co-location arrangements, including whether data centers and nuclear plants will pay any transmission charges.[81]

Even if FERC sets new rules the two sides are likely to continue squabbling about the details. With billions of dollars on the line, each side might have an incentive to litigate, which would add risk to co-location schemes.

III. Recommendations for State Regulators and Legislators: Strategies for Protecting Consumers from Big Tech's Power Costs

Without systematic changes to prevailing utility ratemaking practices, the public faces significant risks that utilities will take advantage of opportunities to profit from new data centers by making major investments and then shifting costs to their captive ratepayers. The industry's current approaches of luring data centers with discounted contracts or lopsided tariffs are unsustainable.

We outline five recommendations for PUCs to better protect consumers from subsidizing Big Tech's data centers: A) establishing guidelines for reviewing special contracts, B) shifting new data centers from special contracts to tariffs, C) facilitating competition and the development of "energy parks" that are not connected to any utility-owned network, D) requiring utilities to provide more frequent demand forecasts;, and E) allowing new data centers to take service only if they commit to flexible operations.

A. Establish Robust Guidelines for Reviewing Special Contracts

PUCs rarely reject proposed special contracts with data centers. As we discussed, many states' laws provide PUCs with broad discretion to approve special contracts, do not specify a particular standard of review, and even allow the PUC to approve a contract that shifts costs to other ratepayers. Given the unprecedented scale and pace of data center special contracts, PUCs should establish more rigorous guidelines for reviewing special contracts that are aimed at protecting consumers.

In Kentucky, the Public Service Commission must make several findings on the record before approving a special contract.[82] Under the PSC's self-imposed guidelines, special contracts that include discounts are allowed only when the utility has excess generation capacity. The guidelines limit discounts to five years and no more than half the duration of the contract. The PSC must also find that the contract rate exceeds the utility's marginal costs to serve that customer and that the contract requires the customer to pay any of the utility's fixed costs associated with providing service to that customer.

Applying its guidelines, the PSC recently rejected a utility's proposed special contract with a cryptocurrency speculator because it found the contract did not shield consumers from the crypto venture's power costs.[83] The PSC was critical of the utility's projections about regional market and transmission prices and therefore did not find credible the utility's claim that the contract would cover the utility's cost to provide energy to the crypto speculator. Industrial ratepayers, several environmental and local NGOs, and Kentucky's attorney general, acting on behalf of consumers, participated in the proceeding and criticized the proposed contract.

While the PSC's guidelines compel it to address vital consumer protection issues, the rule cannot force regulators to critically analyze the utilities' filing or prevent the PSC from merely rubber-stamping a utility's proposed special contract. Vigorous oversight cannot be mandated by law: it requires dedicated public servants. The effectiveness of any consumer protection guidelines depends on the people who implement it, including PUC staff that review utility proposals and the commissioners who make the ultimate decisions. Nonetheless, we believe that establishing guidelines that require regulators to make specific findings about a proposed special contract would improve upon the status quo.

B. Require New Data Centers to Take Service Under Tariffs

Special contracts are vehicles for shifting special interests' energy costs to consumers. Approved in confidential proceedings by PUCs facing political pressure to approve deals and often with no competing interests participating, special contracts allow utilities to take advantage of the subjectivity and complexity of their accounting practices to socialize energy-intensive customers' costs to the public. The existing guardrails that ostensibly allow regulators to police special contracts are not working to protect consumers.

Guided by their consumer-protection mandate, regulators should stop approving any special contracts and instead require utilities to serve data centers through tariffs that offer standard terms and conditions for all future data-center customers. Unlike a one-off special contract that provides each data center with unique terms and conditions, a tariff ensures that all data centers pay under the same terms and that the impact of new customers is addressed by considering the full picture of the utility's costs and revenue. This holistic and uniform approach ends the race-to-the-bottom competition that incentivizes utilities to attract customers by offering hidden discounts paid for by other ratepayers.

That said, standard tariffs are not a talisman for protecting consumers. As we have emphasized, cost allocation is an imprecise exercise that depends on myriad assumptions and projections. However, tariff proceedings and rate cases are more procedurally appropriate forums than a special contract case to consider and address cost-allocation issues. Unlike special contracts, tariffs are reviewed in open dockets that allow the public and interested parties to scrutinize proposals and understand long-term implications of proposed rates should they go into effect. Once approved, a data-center tariff can be revisited in subsequent rate cases where the utility proposes to increase rates and allocate its costs among ratepayers, including data centers. All ratepayers will have an incentive to participate in those cases and offer evidence that challenge data centers' interests.

Several utilities have already been moving away from special contracts to tariffs. Recent and ongoing proceedings are highlighting issues that demand careful scrutiny, including whether to create new data-center-only tariffs and how to protect existing ratepayers from costs of new infrastructure needed to meet data centers' demands. We briefly canvas these issues.

A threshold issue is whether an existing utility tariff for energy-intensive ratepayers is appropriate for data centers or whether a new tariff is necessary to address issues that are unique to data centers. Ratepayer classes are generally defined by the similar costs that the utility incurs to serve members of that class. Data centers may, of course, oppose new tariffs that impose more expensive prices than they would pay if they took service under existing tariffs for energy-intensive ratepayers.

In Ohio, for instance, AEP proposed to create classes for new data centers and cryptocurrency speculators and require ratepayers in those classes to commit to higher upfront charges and for a longer period of time than other energy-intensive consumers.[84] To justify the new data center class, AEP argued that data centers' unique size at individual locations and in the aggregate, as well as uncertainty about their energy use over the long-term and minimal employment opportunities, distinguish data centers from other energy-intensive consumers.[85] Data center companies responded that AEP had "failed to justify its approach to exclusively target data centers" and claimed that the utilities' costs to serve data centers was no different from other energy-intensive consumers that operate around the clock.[86] As of February 2025, the Ohio PUC has yet to rule on AEP's proposal.

FERC addressed similar issues in August 2024 when a utility proposed a new ratepayer class for energy-intensive cryptocurrency operations. Like AEP, the utility claimed that significant but uncertain demand growth justified approval of the new rate class, and therefore higher upfront payment commitments and longer terms for this new customer class were appropriate.[87] According to the utility, crypto speculators can more easily relocate their operations as compared to other energy-intensive consumers, and this mobility amplifies the risk of stranded assets built for new crypto customers that quickly set up shop elsewhere. FERC rejected the proposal because it found that the utility had provided insufficient evidence that new crypto operations "pose a greater stranded asset risk than other loads of similar size."[88] FERC's finding does not foreclose a utility from creating a crypto or data center ratepayer class, but instead signals that FERC will demand more persuasive evidence to justify approval of a new class.

State legislatures could remove any evidentiary hurdles by requiring large data centers to be in their own ratepayer class. With large data centers in their own class, regulators could more easily understand the effects data centers have on other ratepayers. For instance, parties might introduce evidence in a rate case showing how various cost allocation methods that raise costs for data centers would lower costs for other ratepayers. To avoid any claims of undue discrimination, the new rate class might include any new consumer above a specified capacity threshold that, as a practical matter, would likely capture only data centers.

Separating large data centers from other ratepayers could facilitate more protective cost allocation methods that better isolate data center costs from other ratepayers. Again, state legislatures might have a role to play. In Virginia, a bill proposed in January 2025 would require state regulators to determine whether cost allocation methods "unreasonably subsidize" data centers and to minimize or eliminate any such subsidies.[89] Such clear language would provide the PUC with guidance as it balances its obligations to protect ratepayers and facilitate growth in the state. In addition, it would force PUCs to revisit decades-old methods for dividing FERC-regulated transmission costs, as we discuss above.

As data centers shift to new tariffs, the largest potential cost shift in many states could be from the costs of new power plants built to meet data center growth. In most states, utilities are the dominant generation owners and can earn a PUC-set rate of return that they collect from ratepayers on their investments in new power plants. In general, utility expenses on new power plants are spread among ratepayer classes under the theory that all ratepayers benefit from the utility's power plants. But the staggering power demands of data centers defy this assumption. Recent tariff proceedings highlight that many utilities are proposing schemes that are not adequately shielding ratepayers from the costs of new generation for data center growth.

In Indiana, the utility Indiana Michigan Power expects new data centers to increase the peak demand on its system from 2,800 to 7,000 megawatts.[90] To facilitate this growth, the utility proposed to create special terms for new customers that demand at least 150 megawatts of power, a threshold that in practice limits their applicability to new data centers.[91] Like AEP Ohio's proposal, the updated tariff would require a new data center to commit to paying 90 percent of the utility's costs of new generation and transmission capacity needed to meet the data center's demand.[92] This 90 percent capacity payment and the tariff's twenty-year term, according to the utility, would "provide reasonable assurance" that data centers' payments to the utility "will reasonably align with the cost of the significant investments and financial commitments the Company will make to provide service."[93]

Consumer advocates generally supported the utility's efforts to insulate ratepayers from data centers' energy costs but argued that the proposed terms were "insufficient for protecting existing customers from large potential cost shifts in the event of the closure" of a large data center.[94] One of their solutions was to "firewall" the costs of new power plants built to meet data center growth from other ratepayers by requiring the utility to separately procure or build generation for data centers, and then allocating all costs solely to data centers.[95] Consumer advocates also urged regulators to require other modifications related to contract termination and other provisions to protect ratepayers from stranded costs if data center growth failed to materialize or decreased following an initial spike.[96]

Data center companies argued the other side, claiming that the terms were too onerous and benefited the utility shareholders who "would be shielded from business risk, while reaping regulated returns on large potentially more risky expansion of rate base" that would be backed by data centers.[97] Amazon observed that the utility's proposed twenty-year term is based on the ordinary approach to cost recovery of utility capital investments. But instead of the utility building its own plants and earning a return on them, Amazon claimed that the utility could more efficiently support data center growth through short-term contracts with non-utility generators or purchases via PJM's regional markets.[98] Amazon argued that rather than "imposing virtually all risks" associated with power plant development on data centers and reaping all of the profits for itself, the utility should instead share the risks of infrastructure development with new data centers.[99]

The Indiana proceeding highlights how utility ownership of generation can exacerbate cost shifts that benefit utility shareholders. The traditional utility business model of decades-long cost recovery of new utility-owned power plants through consumer rates is not designed to address a near-term tripling of a utility's demand due to just a few giant energy-guzzling warehouses. While "firewalling" data centers' power plant costs from other ratepayers is a viable approach, regulators must ensure that utility proposals actually protect consumers.

Under its "Clean Transition Tariff," Nevada Energy claims to insulate other ratepayers from data centers' energy generation costs by contracting with new clean energy resources and then passing those contract costs directly to a specific data center or other customer. In theory, this arrangement could isolate generation costs, but public utility staff and other intervenors concluded that the new tariff would not actually firewall data centers' generation costs from other ratepayers.[100] They found that complex interactions between the new tariff's proposed pricing structure and existing tariffs would shift costs to other ratepayers. For instance, PUC staff focused on the utility's proposal to account for the revenue it would have earned if the data center took service under a standard tariff and then charge other ratepayers for a portion of its “lost” revenue.[101] In February 2025, the utility agreed with intervenors to modify its proposal and defer consideration of some of these complicated cost allocation issues.[102]

A better option for protecting ratepayers from power plant costs would be to allow data centers to purchase energy directly from non-utility retailers but still pay the utility for delivery service. Several states allow for such retail competition for energy-intensive consumers. To even further isolate data center energy costs, regulators could cut the cord entirely between the utility and data centers. Off-the-grid energy parks or energy parks that only export energy to the utility could completely insulate ratepayers from data centers' energy costs.

C. Amend State Law to Require Retail Competition and Allow for Energy Parks

Competition can protect consumers from utility market power and insulate ratepayers from cost shifts. Starting in the 1970s, a few states began to allow limited competition for electricity service to certain energy-intensive consumers.[103] In the 1990s, about a dozen states permitted all ratepayers to shop for power supply while continuing to require them to pay state-regulated rates for utility-provided delivery service. Additional states allowed energy-intensive consumers to similarly choose a power supplier. To protect ratepayers, states could require new data centers to procure power through competitive processes rather than confining them to utility-supplied power. States could go further and allow or require new data centers to isolate entirely from the utility-owned network by creating new energy parks.

A mandate that new data centers procure power from non-utility suppliers would protect ratepayers from short-term costs and long-term risks. Requiring the data center to contract with a competitive supplier rather than with the utility would ensure that all stranded costs associated with the generation are allocated between the data center and its supplier. In addition, isolating the utility from the deal would obviate the need for the type of complex energy price calculations, integral to Nevada Energy's proposal, that link the data center's power price to the costs of the utility's legacy assets.

The costs of utility-built power plants for data centers could be astronomical. In the Indiana proceeding discussed in the previous section, the utility's own estimates revealed that if it met data center demand with self-built plants it could spend as much as $17 billion on new power plants over the next several years.[104] The utility's proposal to require data centers to commit to paying 90 percent of the infrastructure costs over a twenty-year period would improve upon the status quo but would not completely isolate those costs from other ratepayers, particularly if data center demand did not meet the utility's forecasts.

Even with a state prohibition on new utility power plants for meeting data center demand, ratepayers could still face higher bills from cost shifts. A data center procuring energy from the market would still pay utility-imposed delivery charges that could obscure discounts for data centers or include various other cost shifts. Islanding the data center and its power supply from the utility-owned system is a sure-fire approach for protecting ratepayers.

An energy park, according to a recent paper by Energy Innovation, "combines generation assets, complementary resources like storage, and connected customers."[105] Unlike typical behind-the-meter arrangements where a customer installs some on-site generation to complement utility-delivered power, an energy park would provide sufficient power for the connected customers' operations. This arrangement is "particularly compelling for large customers due to the cost advantages of sourcing electricity directly from the cheapest, cleanest sources and due to the challenges of connecting large capacities to the existing grid."[106] Avoiding the protracted utility-run interconnection processes would be a benefit for Big Tech companies who tend to move faster than the lumbering utility industry.[107]

A fool-proof way to insulate utility ratepayers from data center energy costs is to isolate a data center energy park from the utility-owned network. Isolation may be difficult, however, as an interconnected energy park could be more financially attractive to developers, even if it is only able to export power to the transmission system and unable to import utility-delivered power.[108] Connecting an energy park would require a utility-run interconnection process and would likely lead to the utility imposing transmission charges on the energy park. While transmission charges associated with an export-only energy park could facilitate cost shifts, they are likely to be much smaller than those embedded in special contracts and other arrangements for serving data centers with utility-delivered power that we have outlined in this paper.

Both competitive generation and energy park development face the same legal obstacle: state protection of utility monopolies. Under many states' laws, an entity that delivers or sells power to another entity is a "public utility." For instance, if a generation company owns the park's generation assets and Big Tech company owns the data center, the generation company would be regulated as a public utility. This designation could doom the project. States typically prohibit competition for electric service and regulators and courts might enforce the state's monopoly protections by prohibiting a multi-owner energy park located within the territory assigned to the incumbent utility.[109] Even if a state allows the energy park to move forward as a public utility, the PUC may be compelled to regulate its rates and terms of service in a way that render the project unviable.

One potential workaround is to locate an energy park outside a for-profit utility's service territory. But states' laws may nonetheless impose obstacles. In Georgia, for instance, state law allows a new energy-intensive consumer located outside existing utility service territories to choose a supplier but limits the premises to a single customer.[110] An energy park in Georgia could therefore include only one data center owner. Energy parks might also be able to locate within the service territory of a municipal or cooperative utility. The service territories of these non-profit entities may not be protected by state law, or they may not be financially motivated to defend their monopolies and might instead welcome an energy park's investment in their communities.[111] That said, some non-profit utilities may regard an energy park as an infringement on their monopolies.[112]

State legislatures could amend anachronistic laws that prevent energy park development and block data centers taking utility service from procuring non-utility generation. To avoid interminable utility complaints that competition harms consumers,[113] laws could be tailored to apply only to data centers or other energy-intensive consumers that would otherwise require a utility to incur significant costs to procure power or build new generation.

D. Require Utilities to Disclose Data Center Forecasts

For competition to be effective, market participants need information about potential data centers' location and power demands. When utilities withhold that information, they prevent generators and other infrastructure and technology developers from offering data centers solutions that compete with the utility's offering. PUCs could require utilities to file monthly or quarterly load forecasts, which would reduce utilities' informational advantages and better enable other companies to offer solutions that would protect ratepayers from a utility's ability to shift data centers' costs to other consumers.

In the AEP Ohio proceeding, a trade association representing non-utility companies that sell electricity to consumers uncovered that AEP was withholding information. It documented that the utility's demand forecasts it filed in prior proceedings were inconsistent with its projections about data center growth it revealed to justify its data center tariff proposal.[114] The trade association's analyst explained that by holding back information AEP "conferred a *de facto* competitive advantage to build transmission rather than allowing a market response from competitive merchant generation" to meet data center demand.[115] The analyst also conjectured that AEP's concealment might directly harm ratepayers if it delayed development of generation that might be needed to meet growing regional demand, which could lead to increased prices in PJM's capacity auction.[116]

PUCs can order utilities to provide demand projections more frequently and specify that utilities include new energy-intensive consumers at various stages of development. Utilities could also provide potential locations and demands of new energy-intensive consumers with enough specificity to be useful to market participants but sufficiently obscured to protect consumers' potentially confidential business information. Because many utilities have substantially increased their demand forecasts over the past year,[117] new reporting rules would be well justified as a means of protecting consumers, enabling competition, and ensuring reliability.

E. Allow New Data Centers to Take Service Only if They Commit to Flexible Operations that Can Reduce System Costs

State regulators could require utilities to condition service to new data centers on a commitment to flexible operations. This approach could benefit all ratepayers by avoiding or reducing the need for expensive infrastructure that would otherwise be needed when a new data center increases the utility's maximum demand. A study by researchers at the Nicholas Institute for Energy, Environment & Sustainability estimates that 76 GW of data centers could connect to the system if utilities curtail energy delivery for just a few hours per year.[118]

As discussed above, utilities and RTOs plan power system expansion to provide sufficient capacity for meeting consumers' maximum energy demand, which usually occurs on the hottest and coldest days of the year. Because the system is planned for these extreme weather days, a large portion of a power system's generation and delivery infrastructure is underutilized for most of the year. If a data center commits to reducing its consumption of utility-supplied power during peak demand periods, utilities could deliver power to the data center without building new infrastructure.

To implement a flexibility mandate, PUCs could order utilities to modify their tariffs and classify data center loads as interruptible customers whose power can be turned off under specified circumstances. Similarly, regulators could also require utilities to modify their interconnection procedures to designate data centers as controllable loads that must reduce their consumption under certain conditions.[119] These strategies could defer the immediate need for costly infrastructure upgrades to serve new data centers. Utilities, however, have historically been hostile to regulatory attempts to require measures that would defer or avoid the need for costly infrastructure upgrades that drive utilities' profits.

IV. Subsidies Hidden in Utility Rates Extract Value from the Public

Utility rates have always been a means of achieving economic and energy policy goals. By financing favored investments through utility rates, rather than through general government revenue, policymakers can avoid having to raise taxes and instead conceal public spending through complex utility rate increases. From the public's perspective, hiding subsidies in utility rates may be acceptable if the benefits of the favored investments exceed their costs. For data centers deals, however, utilities do not publicly demonstrate that ratepayers pay lower rates as a result of the contract. To the extent data center development offers other benefits, such as expanding the local economy or advancing national security interests, we argue that these secondary effects are either already accounted for through other policies or irrelevant to utility regulators.

The economic harm to ratepayers from data center discounts extends beyond the short-term bill increases that utilities are imposing on the public. We are concerned that meeting data center demand is delaying opportunities to initiate power sector reforms that would benefit all ratepayers. To power new data centers, utilities are proposing more of the same: spending capital on large central-station power plants and transmission reinforcements. These types of projects have been fueling utility profits for generations, but the power sector today can do so much more. Deploying advanced technologies and adopting new operational and planning practices could squeeze more value from existing utility systems, but these low-capital-cost solutions are not profitable for utilities and therefore not pursued.[120] By approving special contracts for data centers and tariffs that do protect ratepayers from Big Tech's energy costs, PUCs may be inadvertently fostering an alliance between utilities and Big Tech that could reinforce the industry's technological status quo.

A. Data Center Subsidies Fail Traditional Benefit-Cost Tests

When a utility spends money to supply a new data center, the data center should pay for those investments. However, if ratepayers ultimately benefit from new infrastructure needed for a data center, it may be reasonable for the utility to charge ratepayers a portion of the costs. The "beneficiary pays" principle, an analogue of the cost causation standard, justifies short-term bill increases when they are offset by longer term benefits that reduce ratepayers' bills. Just as consumers should pay costs that reflect a utility's cost to serve them, a utility may charge consumers for projects that ultimately lower their rates.

PUCs have applied the beneficiary pays approach in numerous contexts. For example, many states fund energy efficiency programs through utility rates. These programs directly benefit the ratepayers that make use of the program's discounts for energy audits, new appliances, and other interventions that can reduce power use. All ratepayers are billed for these subsidies that flow directly to a handful of individual consumers that take advantage of these benefits. PUCs approve of this spending when programs ultimately lower peak system demand or otherwise reduce power system costs more than the costs of funding the efficiency program. We acknowledge, however, that these calculations are premised on assumptions and judgments and can be as imprecise as the cost allocation exercises we critique in this paper. The best regulators can do is conduct these analyses transparently, which allows for judicial review, limits the potential for arbitrary regulatory decisions, and provides a basis for changing the policy in response to new evidence.

In special contract proceedings, utilities and PUCs offer no such transparency about data center deals. Instead, billion-dollar contracts are proposed and approved without public accounting of the costs and benefits. Given the stakes and the incentives of the parties, the burden ought to be on utilities to prove publicly that ratepayers are benefiting from these deals, or at worst are being held harmless.

Ratepayers should not be saddled with costs due to data centers' purported strategic national importance. In January 2025, the Biden administration declared that AI is "a defining technology of our era" that has a "growing relevance to national security."[121] "Building AI infrastructure in the United States on the time frame needed to ensure United States leadership over competitors," according to the Biden administration, will "prevent adversaries from gaining access to, and using, powerful future systems to the detriment of our military and national security."[122] If this frightening scenario proves true — that AI will be a privately owned global weapon — it's not clear what it has to do with utility rates.

Data center proponents also tout the economic benefits of new development, but the public is already paying for local job growth through their taxes. Apart from discounted utility rates, many data centers separately receive generous state and local subsidies that governments rationalize based on the supposed economic and employment benefits of permitting new development. Several states, for instance, offer sales tax exemptions that allow data center companies to purchase computers, cooling equipment, and other components without paying state tax. In Virginia, the exemption saved data center companies nearly a billion dollars in 2023 alone.[123] Data centers may also benefit from one-off incentive packages. Mississippi is providing an Amazon data center with nearly $300 million of workforce training and infrastructure upgrades.[124] Mississippi will also reimburse Amazon for 3.15 percent of the data center construction costs and provide tax exemptions that could be worth more than $500 million. In lieu of taxes, Amazon will pay approximately $200 million in fees to the county over five years.[125]

B. Data Center Subsidies Interfere with Needed Power Sector Reforms

The power sector needs major upgrades. Investment in new high-voltage transmission is historically low,[126] despite an acute need for new power lines that can connect consumers to cheaper and cleaner sources of energy and improve network reliability.[127] With low interconnectivity, the utility industry is siloed into regional alliances that make little engineering or economic sense. Meanwhile, utilities have been sluggishly slow to adopt monitoring, communications, and computing technologies that can improve the performance of existing high-voltage networks.[128] At the local level, utilities are failing to unlock the potential of distributed energy resources to lower prices.[129]

Data center growth provides utilities with an excuse to ignore these inefficiencies. Utilities don't have to innovate to supply Big Tech's warehouses and are instead offering to meet data center demand with transmission reinforcements and gas-fired power plants, which have been the industry's bread-and-butter for decades. Some utilities are even propping up their oldest and dirtiest power plants to meet data center demand.[130] Neither data centers nor regulators are challenging utilities to modernize their systems.

Power sector stagnation is the fault of utilities and the regulatory construct that incentivizes inefficient corporate decisions. Rate regulation enables excessive utility spending that crowds out cheaper alternative investments. Because they are monopolists, utilities do not face competition that might expose their inefficiencies. Regulated rates rarely punish utilities for inefficiencies or reward them for improving their operations through low-cost technologies. Ultimately, regulators must try to align utility performance with consumers' interests, but achieving this straightforward objective is dauntingly complex.

Data center growth now overwhelms many PUC agendas. By law, regulators must respond to utility proposals about rate increases, special contracts, infrastructure development, and other issues. Utilities' messaging to regulators and investors is that meeting data centers' growth targets is an urgent priority. The implication is that there's no time to act differently. With utilities' push for growth dominating their dockets, PUCs may find it even harder to reform inefficient utility practices and block unneeded investments. For ratepayers, beneficial projects will remain unfunded, and wasteful utility practices will persist.

As utilities wring profits from the public through special contract approvals, they may be developing a new alliance with Big Tech. Uniting utilities' influence-peddling experience with the deep pockets of Big Tech could further entrench utility control over the power sector. Utilities are already among the largest donors to state elected officials and have a century of experience navigating state legislatures and agencies to protect their monopoly control and otherwise advance their interests. A long-term partnership to push the common interests of utilities and data centers at statehouses, PUCs, and other forums could undermine reform efforts and harm ratepayers.

While energy-intensive consumers typically have a financial incentive to participate in PUC proceedings and argue for their own self-interest by opposing wasteful utility spending, we are concerned that a different scenario may play out for data centers. If utilities' growth predictions are realized, some utilities will have invested billions of dollars to serve data centers that will consume *a majority of all power* delivered by the utility. Under this scenario, the utility will be dependent on its data center customers for revenue and will need to retain them in order to justify its prior and future expansion. To prevent data center departures and attract new data center customers, utilities might continue to offer discounted rates. Rather than acting as watchdogs in PUC proceedings, data center companies may instead focus on securing more discounts. Insulated by special contract deals and favorable tariffs with friendly utilities, data center companies would focus on defending their discounts rather than disciplining the utility's spending in rate cases.

Outside of formal proceedings, utility-Big Tech alliances could amplify pro-utility political messages. Utilities have a pecuniary interest in the laws that govern PUC decisionmaking and push for changes that benefit their bottom lines. Utilities formally lobby state legislators and also pursue an array of public relations strategies to secure favorable legislative and regulatory outcomes. Big Tech has the financial capacity to significantly increase the amount of money supporting of pro-utility bills and regulatory actions.

An alternative approach — which requires data centers to power themselves outside of the utility system — sets up a formidable counterweight to utilities' monopoly power. If Big Tech is forced to power itself, it might defend against utility efforts to limit competition and return to the pro-market advocacy that characterized the Big Tech's power-sector lobbying efforts prior to the ChatGPT-inspired AI boom.

Appendix A

Big Tech Companies and Data Center Developers Testifying that
Utility Prices Inform Where They Build New Facilities

- AEP Ohio Proposed Tariff Modifications, *supra* note 2, Motion to Intervene and Memorandum in Support of Sidecat, an Affiliate of Meta (Jun. 10, 2024) ("The applicable electricity rates and corresponding electric service tariffs for AEP Ohio will be a significant consideration for Meta when evaluating possible sites for new facilities, expansions at existing facilities, and otherwise operating its data center assets.").
- AEP Ohio Proposed Tariff Modifications, Direct Testimony of Brendon J. Baatz in Opposition of the Second Joint Stipulation and Recommendation, at 4 (Nov. 8, 2024) ("the terms and conditions in Schedule DCT are far more restrictive and burdensome than those imposed by investor-owned utilities in other states, which could prompt some data center customers to consider investing outside of Ohio").
- AEP Ohio Proposed Tariff Modifications, Second Supplemental Direct Testimony of Michael Fradette, on Behalf of Amazon Data Services, Inc., at 18 (Nov. 8, 2024) ("By rejecting a stipulation that unfairly discriminates against data centers, the Commission can help ensure that Ohio continues to be a leader in attracting investment from this vital industry.").
- AEP Ohio Proposed Tariff Modifications, Motion to Intervene of Data Center Coalition, at 4 (May 24, 2024) ("AEP Ohio's proposals, and potential proposals made by intervenors in the case, may have a significant impact on existing and planned data centers in AEP Ohio's service territory.").
- AEP Ohio Proposed Tariff Modifications, Direct Testimony of Brendon J. Baatz, at 11 (Oct. 18, 2024) ("If AEP Ohio's proposal is adopted, it would create an unfavorable environment for data center development in the state, potentially causing companies to reconsider their investment plans.").
- AEP Ohio Proposed Tariff Modifications, Direct Testimony of Kevin C. Higgins on behalf of The Data Center Coalition, at 7 (Oct. 18, 2024) ("If approved, the DCP tariff will adversely impact planned data center development in the Company's service territory."); *id.* at 11 ("At the same time, it is important that the Commission not take actions that would depress the growth of an important emerging industry by imposing unjust and discriminatory terms.").
- Indiana Michigan Power Proposed Tariff Modification, *supra* note 15, Direct Testimony of Kevin C. Higgins on behalf of The Data Center Coalition, at 6 (Oct. 15, 2024) ("If

approved, the IP Tariff changes could adversely impact planned data center development in the Company's service territory.").

- Indiana Michigan Power Proposed Tariff Modification, Direct Testimony of Justin B. Farr on behalf of Google, at 23 (Oct. 15, 2024) ("Modifications . . . have the potential to limit opportunities for . . . the development of shared solutions that can provide significant benefit to I&M's system by removing the financial incentive for I&M to collaborate with its customers to pursue innovative solutions to support their growth.").
- Indiana Michigan Power Proposed Tariff Modification, Direct Testimony of Michael Fradette on behalf of Amazon Data Services, Inc., at 37 (Oct. 15, 2024) ("The proposed [tariff] is not reasonable and in fact has a negative impact on Amazon's view for future investment actions within I&M's service territory. I&M has offered no reasonable justification for revising Tariff I.P. as proposed.").
- Contracts for Provision of Electric Service to a New Large Customer's Minnesota Data Center Project, Minn. Pub. Util. Comm'n Docket No. 22-572, Petition, at 28 ("The customer has made clear that the CRR Rate is critically important to its decision to select a site in Minnesota for its new data center. Without the CRR Rate, the economic feasibility of this new data center would be jeopardized.").
- In re Application of Pub. Serv. Co. of Colorado for Approval of a Non-Standard EDR Contract, Pub. Util. Comm'n of Colorado Proceeding No. 23A-0330E, Direct Testimony & Attachment of Travis Wright on behalf of Quality Technology Services, at 8 (Jun. 23, 2023) ("QTS selects its new locations extremely carefully. Electricity is one of the major costs to operating a data center, so the low EDR rate provided by Public Service, and the term of the EDR agreement, is a critical factor in determining to locate in Aurora."); *id.* at 10–11 ("Given that approximately 40 percent of the Aurora QTS Campus's operational expense will be attributable to utilities, with electric being the largest component, the cost per kWh can easily make or break a project, or drive QTS or its customers to invest resources elsewhere. The EDR ESA that we have negotiated with Public Service and are requesting approval of in this Proceeding, is a critical component of our business model for the Aurora QTS Campus."); *id.* at 16 ("Was the cost of electricity a critical consideration for QTS in deciding where to site its new operations? Yes. 40 percent of the operational cost of a data center is electricity, and this will usually be the largest line item on the budget. Additionally, this cost will continue for 40 years, and will scale the business. In contrast, real estate and development costs are one-time, up-front expenditures that are watered down as the

volume of business increases. The largest and fastest growing operations in our portfolio are in markets where electricity costs are competitive.”).

- In re Application of Ohio Power Company and New Albany Data Center, LLC for Approval of a Reasonable Arrangement, Pub. Util. Comm’n of Ohio Case No. 23-0891-EL-AEC, Joint Application, at 7 (Sep. 28, 2023) (“Without this reasonable arrangement, NADC could construct its own dedicated substation and take lower-cost service under AEP Ohio’s transmission voltage tariff – to the extent it would decide to develop its facilities in AEP Ohio’s service territory.”).
- Application of Nevada Power Company for Approval of an Energy Supply Agreement with Lumen Group, Pub. Util. Comm’n of Nev. Docket No. 19-12017, Application, Attachment A: Long Term Energy Supply Agreement White Paper, at 17 (Dec. 19, 2019) (“The ESA provides Google with important benefits . . . the blended rate provided for in the ESA is cost-effective and competitively priced compared to other available options, the fixed-price nature of the agreement provides Google with important cost-certainty into its energy expenditures . . .”).

Endnotes

* Eliza Martin is a Legal Fellow in the Environmental and Energy Law Program at Harvard Law School. Ari Peskoe is the Director of the Electricity Law Initiative. We thank Kent Chandler, Josh Macey, Abe Silverman, and Megan Wachspress for thoughtful feedback on our draft.

[1] *See, e.g.*, JOHN D. WILSON, ZACH ZIMMERMAN & ROB GRAMLICH, STRATEGIC INDUSTRIES SURGING: DRIVING US POWER DEMAND 8 (Grid Strategies, Dec. 2024) [hereinafter Grid Strategies Report]; Alastair Green et al., *How Data Centers and the Energy Sector Can Sate AI's Hunger for Power*, MCKINSEY & CO., ("Much of data center growth — about 70 percent — is expected to be fulfilled directed or indirectly (via cloud services, for instance) by hyperscalers by 2030"); EPRI, POWERING INTELLIGENCE: ANALYZING ARTIFICIAL INTELLIGENCE & DATA CENTER ENERGY CONSUMPTION 7 (May 2024) [hereinafter Powering Intelligence]; Jennifer Hiller & Katherine Blunt, *Inside the Audacious Plan to Reopen Three Mile Island's Nuclear Plant*, WALL ST. J. (Nov. 10, 2024), ("Analysts at Jefferies estimate Microsoft will pay between $110 and $115 per megawatt hour of electricity").

[2] *See, e.g.*, In re *Application of Ohio Power Company for New Tariffs Related to Data Centers*, Pub. Util. Comm'n of Ohio Case No. 24-508-EL-ATA [hereinafter AEP Ohio Proposed Tariff Modifications], Direct Testimony of Kevin C. Higgins on behalf of The Data Center Coalition, at 7 ("If approved, the [proposed] tariff will adversely impact planned data center development in the Company's service territory."); *id.* at 11 ("At the same time, it is important that the Commission not take actions that would depress the growth of an important emerging industry by imposing unjust and discriminatory terms."). *See* Appendix A for additional evidence.

[3] See, *e.g.*, Rich Miller, *Skybox Plans 300-Megawatt Campus South of Dallas*, DATA CENTER FRONTIER (Nov. 20, 2023); City of Cleveland, Office of Sustainability & Climate Justice (noting that the city has a 300-megawatt system).

[4] Palo Verde is the largest nuclear power station in the U.S. Its three reactors produce approximately 3.3 gigawatts. Meta announced a two-gigawatt data center development in December 2024. *See* Dan Swinhoe & Zachary Skidmore, *Meta Announces 4 Million Square Foot, 2 GW Louisiana Data Center Campus*, DATA CENTER DYNAMICS (Sep. 5, 2024).

[5] See *generally* Powering Intelligence; Alastair Green et al., *How Data Centers and the Energy Sector Can Sate AI's Hunger for Power*, MCKINSEY & CO.

[6] See, *e.g.*, Grid Strategies Report ("[A]nnual peak demand growth will average 3% per year over the next five years. While 3% growth may seem small to some, it would mean six times the planning and construction of new generation and transmission capacity.").

[7] *See* FED. ENERGY REG. COMM'N, SUMMER ENERGY MARKET & ELECTRIC RELIABILITY ASSESSMENT 46 (May 23, 2024) (showing 19 GW actual demand in 2023); Newmark, 2023 U.S. DATA CENTER MARKET OVERVIEW & MARKET CLUSTERS 7 (Jan. 2024) (projecting 35 GW in 2030); *AI is Poised to Drive 160% Increase in Data Center Power Demand*, Goldman Sachs (May 14, 2024).

[8] See Grid Strategies Report, at 12.

[9] See Georgia Power Company, Georgia Pub. Serv. Comm'n Docket No. 56002, Budget 2025: Load and Energy Forecast 2025 to 2044 (Jan. 31, 2025); Drew Kann and Zachary Hansen, *Data Centers Use Lots of Energy: Georgia Lawmakers Might Make Them Pay More*, THE ATLANTA JOURNAL CONSTITUTION (Feb. 13, 2025) (stating that Georgia Power executives stated that 80 percent of the company's forecasted electricity demand growth is due to data centers).

[10] Press Release, *Oncor Electric Delivery Company, Oncor Reports Third Quarter 2024 Results* (Nov. 6, 2024),.

[11] Robert Walton, *ERCOT Successfully Navigates Heat Wave, New Peak Demand Record*, UTILITY DIVE (Aug. 26, 2024).

[12] See Ethan Howland, *AEP Faces 15 GW of New Load, Driven by Amazon, Google, Other Data Centers: Interim CEO Fowke*, UTILITY DIVE (May 1, 2024); American Electric Power, 4th Quarter Earnings Presentation (Feb. 13, 2025).

[13] See, e.g., In re Application of Ohio Power Company for New Tariffs Related to Data Centers, Pub. Util. Comm'n of Ohio Case No. 24-508-EL-ATA [hereinafter AEP Ohio Proposed Tariff Modifications], Direct Testimony of Matthew S. McKenzie on Behalf of Ohio Power Company [hereinafter Ohio Power Company Testimony], at 2 (May 13, 2024)

[14] Indeed, investors are taking note. The authors have on file numerous reports from utility stock analysts that tout the potential of data center growth. Utilities' presentations to investors claim that data center growth will drive future earnings. *See, e.g.*, AEP 4th Quarter Earnings Presentation, *supra* note 13, at 13 (stating that "Load Growth Supports Financial Strength" and noting it is being driven by data centers).

[15] *See, e.g.*, In re *Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Tariff*, Indiana Util. Reg. Comm'n Cause No. 46097 [hereinafter Indiana Michigan Power Proposed Tariff Modifications], Testimony of Indiana Consumer Advocates, at 4 (Oct. 15, 2024) ("There has been a significant lack of transparency with these new loads . . . For example, with respect to new large loads coming to I&M's service territory, Google and Microsoft refused to answer CAC data requests about their anticipated load and electricity consumption, and Microsoft also refused to identify its forecasted load factor. CAC counsel reached out to counsel to these parties and requested to execute a non-disclosure agreement with each respective company so that CAC could obtain this pertinent information, but thus far, we have not received a proposed non-disclosure agreement or the confidential information."). Most of the figures in the Georgia Power filing cited at note 9 are redacted.
[16] *See, e.g.*, AEP Ohio Proposed Tariff Modifications, Ohio Power Company Testimony, *supra* note 13, at 2 ("Currently, AEP Ohio has limited ability to distinguish customers who are merely speculating on potential data center investments from customers who are willing to make long-term financial *commitments* to data center investments.") (original emphasis); *Large Loads Co-Located at General Facilities Technical Conference*, FERC Docket No. AD24-11-000, Transcript, at 26 (Aubrey Johnson, Vice-President, Systems & Resource Planning for the Midcontinent Independent System Operator explaining that "in many cases, these data centers are showing up in multiple places, so I have many members submitting loads that are all the same. So how do we have more clarity . . . to understand what the actual true load is?").
[17] *See generally* Powering Intelligence, at 7.
[18] *See, e.g.*, David Uberti, *AI Rout Sends Independent Power Stocks Stumbling*, WALL ST. J. (Jan. 27, 2025), ("DeepSeek's efficient approach have 'created panic among investors who question the sustainability of US data center and AI investments,' Guggenheim analysts wrote in a note"); JONATHAN KOOMEY, TANYA DAS & ZACHARY SCHMIDT, ELECTRICITY DEMAND GROWTH AND DATA CENTERS: A GUIDE FOR THE PERPLEXED (Bipartisan Policy Center & Koomey Analytics, Feb. 2025).
[19] The Grainger College of Engineering, *Why DeepSeek Could be Good News for Energy Consumption*, (Feb. 6, 2025); James O'Donnell, *DeepSeek Might Not be Such Good News for Energy After All*, MIT TECH. REVIEW (Jan. 31, 2025).
[20] See Deepa Seetharaman and Tom Dotan, *Tech Leaders Pledge Up to $500 Billion in AI Investment in the U.S.*, WALL ST. J. (Jan. 21, 2025).
[21] Jordan Novet, *Microsoft Expects to Spend $80 Billion on AI-Enabled Data Centers in Fiscal 2025*, CNBC (Jan. 3, 2025).
[22] Press Release, State of Ohio, *Governor DeWine Announces $10 Billion Investment Plan from Amazon Web Services in Greater Ohio* (Dec. 16, 2024).
[23] Dan Swinhoe & Zachary Skidmore, *Meta Announces 4 Million Sq Ft, 2 GW Louisiana Data Center*, DATA CENTER DYNAMICS (Dec. 5, 2024).
[24] *See generally* Aneil Kovvali & Joshua C. Macey, *Hidden Value Transfers in Public Utilities*, 171 PENN. L. REV. 2129 (2023).
[25] KEN COSTELLO, ALTERNATIVE RATE MECHANISMS & THEIR COMPATIBILITY WITH STATE UTILITY COMMISSION OBJECTIVES, NATIONAL REGULATORY RESEARCH INSTITUTE 2 (Apr. 2014).
[26] See U.S. Energy Information Administration, *Electric Power Monthly*, *Table 5.6.A*. *Average Price of Electricity to Ultimate Customers by End-Use Sector* (showing average residential, commercial, and industrial rates in each state).
[27] Alabama Elec. Co-op., Inc. v. FERC, 684 F.2d 20, 27 (D.C. Cir. 1982).
[28] Co. Interstate Gas Co. v. Fed. Power Comm'n, 324 U.S. 581, 590 (1945).
[29] JAMES C. BONBRIGHT, PRINCIPLES OF PUBLIC UTILITY RATES 338 (1961).
[30] *See, e.g.*, Off. of Consumer Counsel v. Dep't of Pub. Util. Control et al., 905 A.2d 1, 6 (Conn. 2006) ("In the specialized context of a rate case, the court may not substitute its own balance of the regulatory considerations for that of the agency, and must assure itself that the [department] has given consideration of the factors expressed in [the statute]."); Iowa-Ill. Gas & Elec. Co. v. Ill. Com. Comm'n, 19 Ill. 2d 436, 442 (Ill. 1960) (explaining that deference to the Commission is "especially appropriate in the area of fixing rates"); Farmland Ind., Inc. v. Kan. Corp. Comm'n, 37 P.3d 640, 650 (Kan. App. 2001) (providing that the Kansans Corporation Commission "has broad discretion in making decisions in rate design types of issues"); Ohio Consumers' Counsel v. Pub. Util. Comm'n, 926 N.E.2d 261, 266 (Ohio 2010) ("The lack of a governing statute telling the commission how it must design rates vests the commission with broad discretion in this area.").
[31] *See* *2024 FERC Rep. on Enforcement*, FERC Docket No. AD07-13-018, at 51 (Nov. 21, 2024) ("Most audits find that public utilities recorded non-operating expenses and functional operating and maintenance expenses

in [Administrative and General] expense accounts, leading to inappropriate inclusion of such costs in revenue requirements produced by their formula rates"); *see also infra* note 34.

[32] *FirstEnergy Corp.*, FERC Docket No. FA19-1-000, Audit Report, at 48 (Feb. 4, 2022).

[33] *Id.* at 16.

[34] *See, e.g.*, *Application of Southern California Gas Company for Authority to Update its Gas Revenue Requirement and Bas Rates*, California Pub. Util. Comm'n Application 22-05-015, Decision 24-12-074, at 7 (Dec. 19, 2024) ("The decision [to use one-way balancing accounts] highlights a pattern of misclassification of costs at Sempra Utilities, where the company has charged ratepayers for lobbying, political activities, and expenses related to outside legal firms. These costs have been improperly booked as above-the-line expenses when forecasting future costs."); *Order Instituting Rulemaking*, California Pub. Util. Comm'n Rulemaking 13-11-005, Decision 22-04-034 (Apr. 7, 2022) ("As an experienced utility, SoCalGas should have known that its billing of lobbying against reach codes implicates several basic legal principles that are central to its duties to the Commission and to customers . . . Thus, aside from billing ratepayers for lobbying contrary to the intent of the Commission, SoCalGas appears on the face of the record to have misled staff about the direction of its lobbying…."). *See also 2024 FERC Rep. on Enforcement*, FERC Docket No. AD07-13-018, at 58 (Nov. 21, 2024) (summarizing that FERC audits revealed "improper application of merger-related costs; lobbying, charitable donation, membership dues, and employment discrimination settlement costs; improper labor overhead capitalization rates….").

[35] Costello, *supra* note 25, at 44. *See also Investigation into the Reasonableness of Rates & Charges of PacifiCorp*, Utah Pub. Serv. Comm'n Docket No. 99-035-10, 2000 WL 873337 (2000) ("[E]ach class of service does not pay precisely its 'share' of costs. This is true, for example, of the large customer groups, or special contract customers, according to some views of allocations.").

[36] *See, e.g.*, MINN. STAT. § 216B.162, subd.7 (2024); COLO. REV. STAT. ANN. § 40-3-104.3 (West 2018); MICH. COMP. LAWS § 460.6a(3).

[37] KAN. STAT. ANN. § 66-101i.

[38] See MISS. CODE ANN. § 77-3-271(3) ("A public utility may enter into a large customer supply and service agreement with a customer, which may include terms and pricing for electric service without reference to the rates or other conditions that may be established or fixed under Title 77, Chapter 3, Article 1, Mississippi Code of 1972. No approval by the commission of such agreement shall be required. With respect to such an agreement…the agreement, including any pricing or charges for electric service, shall not be subject to alteration or other modification or cancelation by the commission, for the entire term of the agreement….").

[39] See Appendix A.

[40] *See, e.g.*, *Application of El Paso Electric Company for an Economic Development Rate Rider for a New Data Center*, Pub. Util. Comm'n Texas Docket No. 56903, Order No. 1 (Aug. 2, 2024) (issuing standard protective order with no analysis); *Petition of Duke Energy Indiana for Approval of a Special Retail Electric Service Agreement*, Indiana Util. Reg. Comm'n Cause No. 45975, Order (Nov. 20, 2023) (granting Duke Energy's motion for confidential treatment); In re *Cheyenne Light, Fuel & Power Co. Petition for Confidential Treatment of a Contract with Mineone Wyoming Data Center LLC*, Wyoming Pub. Serv. Comm'n Docket No. 20003-238-EK-24 (Record No. 17600), Letter Order (Oct. 9, 2024) (authorizing confidential treatment); In re *Xcel Energy's Petition for Approval of Contracts for Provision of Service to a New Large Customer's Minnesota Data Center Project*, Minn. Pub. Util. Comm'n Docket No. E-002/M-22-572, Order (excising significant portions of the proposed service agreement and staff analysis because it is a "highly confidential trade secret"); *Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC*, Kentucky Pub. Serv. Comm'n Case No. 2022-00387, Order (Dec. 4, 2024), at 3 (granting confidential treatment for utility filing and providing that the information "shall not be placed in the public record or made available for public inspection for five years or until further order[ed]").

[41]*See id; see also* Daniel Dassow, *University of Tennessee Professor Sues TVA for Records of Incentives to Bitcoin Miners*, KNOXVILLE NEWS SENTINEL (Oct. 29, 2024) (explaining how there was no information about the incentives that TVA gave a cryptocurrency company to build within its footprint, but that the company used 9.4 percent of all Knoxville Utilities Board electricity in 2023 while employing just thirty people).

[42] See Costello, *supra* note 25, at 21.

[43] See Peter Lazare, *Special Contracts and the Ratemaking Process*, 10 ELEC. J. 67, 68–70 (1997) (quoting a Commonwealth Edison filing that argues long-run costs are appropriate for rate cases and short-term costs are appropriate for special contract proceedings and explaining the implications of using different metrics).

[44]*See, e.g.*, In re *Application of Ohio Power Company and New Albany Data Center, LLC for Approval of a Reasonable Arrangement*, Pub. Util. Comm'n of Ohio Case No. 23-0891-EL-AEC, Order Approving the Application with Modification ("The proposed arrangement meets the burden of proof for obtaining a

reasonable arrangement under Ohio Adm. Code Chapter 4901:1-38. Furthermore, we find that the proposed arrangement, as modified by Staff, is reasonable and should be approved."). Occasionally, a state PUC applying its public interest standard will gesture at a utility's static marginal cost analysis or no-harm analysis for analytical support. *See, e.g.*, *Petition of Duke Energy Indiana for Approval of a Special Retail Electric Service Agreement*, Indiana Util. Reg. Comm'n Cause No. 45975, Order of the Commission (Apr. 24, 2024) ("In making such a determination [that the proposed agreement satisfies Indiana Code], two considerations are important: whether the rates negotiated between the utility and its customer are sufficient for the utility to cover the incremental cost of providing the service to the customer and still make some contribution to the utility's recovery of its fixed costs, and whether the utility has sufficient capacity to meet the customer's needs. As explained by [Duke Energy's Vice President of Rates and Regulatory Strategy], the Agreement requires that Customer cover the incremental costs of providing service to it, as well as contributing to Petitioner's recovery of fixed costs…Based on the evidence of record, we find and conclude that the terms and conditions contemplated in the Agreement are just and reasonable…Therefore, we find that the Agreement is in the public interest and is, therefore, approved…."); In re *Idaho Power Company's Application for Approval of a Special Contract and Tariff Schedule 33 to Provide Electric Service to Brisbie, LLC's Data Center Facility*, Idaho Pub. Util. Comm'n Case No. IPC-E-21-42, Order No. 35958 ("Commission Discussion and Findings: The Commission has jurisdiction over this matter under *Idaho Code* §§ 61-501, -502, and -503…We have reviewed the record in this case and find the Company's August 30, 2023, Filing including an amended ESA, revised Schedule 33, and additional modifications is consistent with the Commission's directive in Order No. 3577.").

[45] See Duke Energy Carolinas, LLC v. NTE Carolinas II, LLC, 111 F.4th 337, 344–46 (4th Cir. 2024).

[46] *Id.* at 347.

[47] *Id.* at 349.

[48] *See* Appendix A.

[49] *See generally* Kovvali & Macey, *supra* note 24.

[50] Cross-Subsidization Restrictions on Affiliate Transactions, 73 Fed. Reg. 11,013 (2008) (codified at 18 C.F.R. pt. 35).

[51] *See, e.g.*, Nantahala Power & Light Co. v. FERC, 476 U.S. 953 (1986).

[52] *See, e.g.*, Nat'l Ass'n of Reg. Util. Comm'rs v. FERC, 475 F.3d 1227, 1285 (D.C. Cir. 2007); Entergy Services, Inc. v. FERC, 319 F.3d 536 (D.C. Cir. 2003); South Carolina Pub. Serv. Auth. V. FERC, 762 F.3d 41 (D.C. Cir. 2014).

[53] PJM, *PJM Board of Managers Approves Critical Grid Upgrades*, PJM INSIDE LINES (Dec. 11, 2023).

[54] Sami Abdulsalam, Senior Manager, PJM Transmission Planning, Reliability Analysis Update at Transmission Expansion Advisory Committee Meeting (Dec. 5, 2023). *See also PJM Revisions to Incorporate Cost Responsibility Assignments for Regional Transmission Expansion Plan Baseline Upgrades*, FERC Docket No. ER24-843, Protest and Comments of Maryland Office of People's Counsel (Feb. 9, 2024) [hereinafter Maryland People's Counsel Protest].

[55] *See generally PJM Interconnection*, 187 FERC ¶ 61,012 at P 6 (2024); Maryland People's Counsel Protest, Affidavit of Ron Nelson, at 5.

[56] See Maryland People's Counsel Protest, Affidavit of Ron Nelson, at 5.

[57] *See Delmarva Power & Light Co. Modification of Retail Transmission Rates*, Maryland Pub. Serv. Comm'n Case No. 8890, Revised Tariff, Attachment E (Jul. 2, 2024) (allocating 68 percent of transmission costs to residential customers); *Potomac Electric Power Co. Modification of Retail Transmission Rates*, Maryland Pub. Serv. Comm'n Case No. 8890, Revised Tariff, Attachment F (Jul. 2, 2024) (allocating 53 percent of transmission costs to residential customers); *Baltimore Gas & Elec. Co. Updated Market-Priced Service Rates, Administrative Charges, and Retail Transmission Rates under Rider 1*, Maryland Pub. Serv. Comm'n Case Nos. 9056/9064, Attachment 2: Development of the Retail Transmission Rates (Apr. 30, 2024) (allocating 78 percent of transmission costs to residential customers).

[58] *Application of Virginia Electric and Power Co.*, Virginia Corp. Comm'n. Case No. PUR-2021-00102, Report of Chief Hearing Examiner Alexander F. Skirpan, Jr., at 9–10 (Jul. 14, 2021).

[59] The cost causation principle could require a shift from transmission rates based on average — or static marginal — costs, to dynamic marginal cost analyses. *See* In re *Application of Pub. Serv. Co. of Colorado for Approval of a Non-Standard EDR Contract*, Colorado Pub. Util. Comm'n Proceeding No. 23A-0330E, Commission Decision Denying Exceptions to Decision No. R24-0168 and Adopting Recommended Decision with Modifications, at 11–12 (May 15, 2024) ("[W]e emphasize that the Commission's review of future Non-Standard EDR contracts must entail detailed examination of how the addition of large loads to the Public Service's system may create a dynamic need for multi-billion new generation and transmission capacity investments that unpredictably show up with no meaningful notice to this Commission and may not be easily

captured in a static marginal cost analysis . . . To that end, the marginal cost analysis that Public Service applied to the EDR ESA with [the data center customer] may not be adequate in future proceedings where the Commission reviews a similar Non-Standard EDR contract especially in light of the rapidly evolving and dynamic interaction between rising demand and the potential costs of serving that growth.").

[60] *Application of Virginia Electric Power,* Virginia Corp. Comm'n. Case No. PUR-2024-00135, Report of Hearing Examiner Bryan D. Stogdale, at 47 (Feb. 14, 2025).

[61] *Application of Virginia Electric Power,* Virginia Corp. Comm'n. Case No. PUR-2024-00135, Report of Hearing Examiner Bryan D. Stogdale, at 23 (Feb. 14, 2025).

[62] *Supra* note 58.

[63] See AEP Ohio Proposed Tariff Modifications, Ohio Power Company Testimony, at 18–20 (May 13, 2024).

[64] See AEP Ohio Proposed Tariff Modifications, Prepared Direct Testimony of Dennis W. Bethel on Behalf of Buckeye Power, Inc. and American Municipal Power [hereinafter Buckeye Power Comments], at 18–19 (Aug. 29, 2024).

[65] *Dayton Power & Light Co.*, 189 FERC ¶ 61,220 (2024).

[66] *Dayton Power & Light Co.*, FERC Docket No. ER25-192, Protest of the Office of the Ohio Consumers' Counsel [hereinafter Protest of the Office of Ohio Consumers' Counsel], at 4 (Nov. 13, 2024); *Dayton Power & Light Co.*, FERC Docket No. ER25-192, Limited Comments of Buckeye Power (Nov. 21, 2024).

[67] Protest of the Office of the Ohio Consumers' Counsel at 5.

[68] *Dayton Power and Light Co.*, 189 FERC ¶ 61,220 at P 23 (2024).

[69] *PJM Interconnection and Virginia Electric and Power Company*, 169 FERC ¶ 61,041 (2019).

[70] *See, e.g.,* Walker Orenstein, *Amazon Wants to Limit Review of 250 Diesel Generators at Its Minnesota Data Center,* MINNESOTA STAR TRIBUNE (Feb. 17, 2025) (noting that Amazon wants to install 600 megawatts of on-site diesel-powered generators at its new data center).

[71] *Constellation Energy Generation v. PJM*, FERC Docket No. EL25-20, Complaint Requesting Fast Track Processing of Constellation Energy Generation, LLC [hereinafter Constellation Complaint], at 20–21 (Nov. 22, 2024).

[72] *Constellation Energy Generation v. PJM*, Docket No. EL25-20, Exelon Comments in Opposition to the Complaint, at 3 (Dec. 12, 2024) ("Constellation refers to Co-Located Load as being 'Fully Isolated' and repeats that term again and again, but it remains untrue. If the loads at issue were truly 'isolated,' the PJM Tariff would not apply to them; no FERC-jurisdictional tariff would. And there would be no reason for this proceeding. As further discussed . . . the loads — whether they are what Constellation labels 'fully isolated' or not — unavoidably rely upon and use grid facilities and grid services in multiple ways. As a matter of physics and engineering, the load is fully integrated with the electric grid — this is the opposite of 'Fully Isolated.'").

[73] *See, e.g., Constellation Energy Generation v. PJM*, FERC Docket No. EL25-20, Comments of the Illinois Attorney General, at 12–13 (Dec. 12, 2024); *Large Loads Co-Located at General Facilities*, FERC Docket No. AD24-11-000, Post Technical Comments of the Organization of PJM States, Inc., at 4 (Dec. 9, 2024) (stating that "[t]ransmission customers have paid the costs of supporting the grid necessary to allow [ ] nuclear facilities to operate").

[74] *PJM Interconnection, LLC*, FERC Docket No. ER24-2172 [hereinafter Susquehanna Nuclear Interconnection Agreement], Protest of Exelon Corporation & American Electric Power Service Corporation, Declaration of John J. Reed & Danielle S. Powers, at 4 (Jun. 24, 2024).

[75] Susquehanna Nuclear Interconnection Agreement, Motion for Leave to Answer and Answer of Constellation Energy Generation and Vistra Corp., at 11 (Jul. 10, 2024).

[76] See PJM, *2025/2026 Base Residual Auction Report*, at 11 (2024).

[77] *See* *2024 Quarterly State of the Market Report for PJM: January Through September*, MONITORING ANALYTICS 3 (2024). *See also* Buckeye Power Comments, at 15 (Aug. 29, 2024) ("Co-location of data centers at existing multi-unit generators (nuclear plants are considered ideal) appears, at first blush, to be attractive as it can 'free-up' transmission capacity by reducing the net output of the generators that the transmission system must deliver. But co-location is a complicated scenario that can disrupt power markets and shift costs by removing large blocks of reliable base load power that will need to be replaced by other sources that will likely require transmission expansion elsewhere."); *Constellation Energy Generation v. PJM*, FERC Docket No. EL25-20, Comments of the Illinois Attorney General, at 3–4 (Dec. 12, 2024) ("The OAG's primary concern regarding co-location arrangements is the impact on resource adequacy and electricity energy and capacity prices . . . . The effect of removing the Illinois nuclear power plant capacity from the ComEd zone and from the PJM market generally can be expected to drive up prices . . . . In light of these multiple factors that are currently putting pressure on prices, co-location arrangements that reserve large blocks of power for discrete customers and prevent them from serving the grid as a whole can be expected to affect the 2027/2028 [capacity prices] . . .

. The OAG is concerned that co-location arrangements that abruptly remove large resources with high capacity values from the grid will cause further devastating price increases while the PJM markets struggle to respond.").

[78] See *infra* Section III.C.

[79] See *Constellation Energy Generation v. PJM*, FERC Docket No. EL25-20, Constellation Complaint, at 6–7 (Nov. 22, 2024) ("competition to serve data center loads [is] a threat to [utilities] bottom line").

[80] *Id.* ("Exelon's utilities already have taken the position that this Commission has decreed that Fully Isolated Co-Located Load is 'impossible' — and shut down any attempt by customers to co-locate data center load in their utility systems. As detailed in their petition for declaratory order filed in Docket No. EL24-149, Exelon is refusing to process necessary studies on these grounds, demanding expensive upgrades under their unified interconnection procedures, delaying agreed-upon work which will force a nuclear plant to take additional outages, and forcing additional services to be procured.").

[81] See *PJM Interconnection, LLC*, 190 FERC ¶ 61,115 (Feb. 20, 2025) (instituting a show cause proceeding pursuant to section 206 of the FPA, and directing PJM and the Transmission Owners to either (1) show cause as to why the Tariff "remains just and reasonable and not unduly discriminatory or preferential without provisions addressing the sufficient clarity or consistency the rates, terms, and conditions of service that apply to co-location arrangements; or (2) explain what changes to the Tariff would remedy the identified concerns if the Commission were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential, and therefore, proceeds to establish a replacement Tariff").

[82] See *In the Matter of: Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC*, Kentucky Pub. Serv. Comm'n Case No. 2022-00387, at 2–4 (Aug. 28, 2023) (citing *Investigation into the Implementation of Economic Development Rates by Electric & Gas Utilities*, Kentucky Pub. Serv. Comm'n Admin. Case No. 327 (Sep. 24, 1990), *aff'd*, Kentucky Power Co. v. PSC of Kentucky, Franklin Circuit Court, Div. 1, Civil Action No. 23-CI-00899 (Dec. 30, 2024)).

[83] *Id.*

[84] See AEP Ohio Proposed Tariff Modifications, Ohio Power Company Testimony, at 2 (May 13, 2024). AEP Ohio requested PUC approval to create two new customer classifications: data centers with a monthly maximum demand of 25 MW or greater, and mobile data centers (cryptocurrency miners) with a monthly maximum demand of 1 MW or greater. AEP's proposed tariff would include new obligations for these customer classes, including a minimum demand charge of 90 percent for data centers, and 95 percent for cryptocurrency facilities, as opposed to the standard 60 percent minimum demand charge for other customers in the general service rate class. AEP Ohio would also require: the two customer classes enter into energy service agreements (ESAs) for an initial term of at least ten years, as opposed to the typical term of one to five years; requirements to pay an exit fee equal to three years of minimum charges should the customer cancel the ESA after five years; collateral requirements tied to the customer's credit ratings; requirements to reduce demand on AEP Ohio's system during an emergency event; and requirements to participate in a separate energy procurement auction than standard offer service customers

[85] *Id.* at 7–8.

[86] AEP Ohio Proposed Tariff Modifications, Initial Comments of Data Center Coalition, at 9–12 (Jun. 25. 2024).

[87] *Basin Electric Power Cooperative*, 188 FERC ¶ 61,132 at PP 15–16, 61 (2024).

[88] *Id.* at P 95.

[89] See H.B. 2101, 2025 Gen. Assemb., Reg. Sess. (Va. 2025).

[90] See Indiana Michigan Power Proposed Tariff Modifications, *supra* note 15, Direct Testimony of Andrew J. Williamson on Behalf of Indiana Michigan Power Company, at 5 (Jul. 19, 2024).

[91] *Id.* at 3, 6–7.

[92] *Id.* at 14.

[93] *Id.*; *id.* at 16 (tariff terms ensure data center provides "reasonable financial support for the significant transmission and generation infrastructure needed to serve large loads").

[94] Indiana Michigan Power Proposed Tariff Modifications, *supra* note 15, Direct Testimony of Benjamin Inskeep on Behalf of Citizens Action Coalition of Indiana, Inc. [hereinafter Citizens Action Coalition of Indiana Testimony], at 25 (Oct. 15, 2024).

[95] *Id.* at 36.

[96] *Id.* at 24–31.

[97] Indiana Michigan Power Proposed Tariff Modifications, *supra* note 15, Direct Testimony of Carolyn A. Berry on Behalf of Amazon Web Services, at 16 (Oct. 15, 2024).

[98] *Id.*

[99] *Id.*

[100] *See generally Application of Nevada Power Company to Implement Clean Transition Tariff Schedule*, Nevada Pub. Util. Comm'n Docket No. 24-05023 [Nevada Power Clean Transition Tariff], Direct Testimony of Manuel N. Lopez on Behalf of Regulatory Operations Staff (Jan. 16, 2025); Nevada Power Clean Transition Tariff, Direct Testimony of Jeremy I. Fisher on Behalf of Sierra Club, Docket No. PUCN 24-05023, at 10–20 (Jan. 16, 2025).
[101] *See generally* Nevada Power Clean Transition Tariff, Direct Testimony of Manuel N. Lopez on Behalf of Regulatory Operations Staff, at 7–8 (Jan. 16, 2025).
[102] Nevada Power Clean Transition Tariff, Stipulation (Feb. 7, 2025).
[103] *See, e.g.*, GA. CODE ANN. § 46-3-8 (allowing utilities to compete to provide service to certain new customers demanding at least 900 kilowatts).
[104] See Indiana Michigan Power Proposed Tariff Modifications, *supra* note 15, Citizens Action Coalition of Indiana Testimony, at 11 (Oct. 15, 2024) ("Using I&M witness Williamson's example portfolio that has an average resource cost of $2,000/kW and has an average accredited capacity of 50%, I&M will also need to make $17.6 billion in new generation investments to serve 4.4 GW of new hyperscaler load.").
[105] ERIC GIMON, MARK AHLSTROM & MIKE O'BOYLE, ENERGY PARKS: A NEW STRATEGY TO MEET RISING ELECTRICITY DEMAND 7 (Energy Innovation Policy & Technology, Dec. 2024).
[106] *Id.* at 8.
[107] *See id.* at 19.
[108] *See id.* at 8–21.
[109] *See, e.g.*, State ex rel. Utilities Commission v. North Carolina Waste Awareness and Reduction Network, 805 S.E.2d 712 (N.C. Ct. App. 2017), *aff'd per curiam*, 371 N.C. 109, 617 (2018).
[110] See Sawnee Electric Membership Corporation v. Public Service Comm'n, 371 Ga. App. 267, 270 (2024) (". . . [T]he text of the Act assigns each geographic area to an electric supplier but also includes the large load exception to allow customers to choose their electric supplier if certain conditions exist . . . the premises must be 'utilized by one consumer and have single-metered service").
[111] See *generally* David Roberts, *Assembling Diverse Resources Into Super-Powered "Energy Parks:" A Conversation with Eric Gimon of Energy Innovation*, VOLTS (Jan. 15, 2025) (featuring an Energy Innovation author describing energy parks in rural cooperative territory in Texas).
[112] *See, e.g.*, Paoli Mun. Light Dept. v. Orange County Rural Elec. Membership Corp., 904 N.E.2d 1280 (Ind. Ct. App. 2009) (ruling in favor of a cooperative utility that sued to prevent a municipal utility from providing electric service to a facility owned by that municipality but located within the cooperative's service territory).
[113] *See, e.g.*, Power for Tomorrow (last visited Jan. 29, 2025), which claims to be "the nation's leading resource" about the "regulated electric utility model" and generally opposes competition with utilities, in part by claiming that competition harms residential consumers. The effort is funded by utilities. *See* Energy and Policy Institute, *Power for Tomorrow* (last visited Jan. 29, 2025).
[114] AEP Ohio Proposed Tariff Modifications, Testimony of Paul Sotkiewicz on Behalf of the Retail Energy Supply Association, at 9–10 (Aug. 29, 2024).
[115] *Id.* at 15.
[116] *Id.* at 14–15.
[117] The trade group's analyst observed that in January 2023 AEP projected only 248 megawatts of data center growth through 2038, but one year later AEP projected 3,700 megawatts of data center growth by 2030. *Id.* at 10 (citing PJM reports).
[118] TYLER NORRIS ET AL., RETHINKING LOAD GROWTH: ASSESSING THE POTENTIAL FOR INTEGRATION OF LARGE FLEXIBLE LOADS IN U.S. POWER SYSTEMS 18 (Nicholas Institute for Energy, Environment & Sustainability, 2025).
[119] *Id.* at 5–6.
[120] See Ari Peskoe, *Replacing the Utility Transmission Syndicate's Control*, 44 ENERGY L. J. 547 (2023).
[121] Exec. Order No. 14,141, 90 FR 5469 (2025).
[122] *Id.*
[123] Va. J. Legis. Audit & Rev. Commission 2024-548, Report to the Governor & the General Assembly of Virginia: Data Centers in Virginia, at viii (2024).
[124] Brody Ford & Matt Day, *Price Tag Jumps for Amazon's Mississippi Data Centers Jump 60% to $16 Billion*, BLOOMBERG (Jan. 31, 2025).
[125] *Id.*
[126] *See generally* NATHAN SHREVE, ZACHARY ZIMMERMAN & ROB GRAMLICH, FEWER NEW MILES: THE US TRANSMISSION GRID IN THE 2020S, GRID STRATEGIES (Jul. 2024).
[127] U.S. Department of Energy, *National Transmission Needs Study* (Oct. 30, 2023).
[128] See Ari Peskoe, *Replacing the Utility Transmission Syndicate's Control*, 44 ENERGY L. J. 547 (2023)

[129] Sonali Razdan, Jennifer Downing & Louise White, *Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update*, U.S. Department of Energy Loan Programs Office (Jan. 2025).
[130] *See, e.g,* Mississippi Power Company's Notice of IRP Cycle, Mississippi Public Service Comm'n Docket No. 2019-UA-231 (Jan. 9, 2025) (stating that because the utility has entered into two contracts with 600 MW of new load it will keep at least one coal plant open that had been slated for retirement); Mississippi Power Special Contract Filing, Mississippi Public Service Comm'n Docket No. 2025-UN-3 (Jan. 9, 2025) (showing that at least one of the two special contracts is with a data center).