**COMMONWEALTH OF KENTUCKY**
**BEFORE THE PUBLIC SERVICE COMMISSION**

In the Matter of:

| | | |
|---|---|---|
| ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS | )<br>)<br>)<br>) | CASE NO. 2025-00113 |

In the Matter of:

| | | |
|---|---|---|
| ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS | )<br>)<br>)<br>) | CASE NO. 2025-00114 |

**DIRECT TESTIMONY OF JAMES FINE ON BEHALF OF JOINT INTERVENORS KENTUCKIANS FOR THE COMMONWEALTH, KENTUCKY SOLAR ENERGY SOCIETY, METROPOLITAN HOUSING COALITION AND MOUNTAIN ASSOCIATION**

**Public Version**

Dated: August 29, 2025

## Table of Contents



## Table of Tables



## Table of Figures

## I. INTRODUCTION & QUALIFICATIONS

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

A. My name is James Fine and my business address is 1118 Grand Street, Alameda, California.

**Q. By whom are you employed and in what capacity?**

A. I am an independent consultant working with M.Cubed. I was employed as a Senior Economist in the Energy Program at Environmental Defense Fund for 17 years, from 2007 through 2024.

**Q. On whose behalf are you submitting testimony in this proceeding?**

A. I am submitting testimony on behalf of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition and Mountain Association (collectively, "Joint Intervenors").

**Q. Please describe your educational background and work experience.**

A. I received my B.S. in Economics from the University of Pennsylvania Wharton School in 1989, and my M.S and Ph.D. from the University of California Berkeley, Energy and Resources Group, in 1999 and 2003, respectively. I have over 25 years of experience working in the field of environmental economics, including energy, with the last ten years focusing primarily on clean energy and transportation electrification policies. I consulted with M.Cubed and Envair from 1994 to 2007. I was an assistant and adjunct professor at the University of San Francisco from 2003 to 2007. From 2007 to 2024, I was served as Economist at the Environmental Defense Fund where my work included resource adequacy assessment, long-term procurement planning, demand response ("DR"), renewable energy, electricity tariff design, transportation electrification and smart grid deployment.

**Q: Have you previously testified before this or any Commission?**

A: I have not previously testified before the Kentucky Public Service Commission. I have provided expert testimony in several proceedings throughout the United States. Particularly relevant testimony includes electricity rate design proceedings in California and Illinois, distributed solar photovoltaic ("DPV") incentive programs in Florida, and advanced rate design in Illinois.

## II. PURPOSE OF TESTIMONY

**Q: What is the purpose and organization of your testimony?**

A: On behalf of a coalition of not-for-profit stakeholders intervening here as Joint Intervenors, my testimony addresses both the proposed changes to Rider NMS-2 ("Net Metering Service 2"), as well as the proposed new Tariff EHLF, ("Extremely High Load Factor") Service.

Regarding the NMS-2 bill credit, I point out that Louisville Gas & Electric Company and Kentucky Utilities Company ("LG&E and KU" or the "Companies") make unreasonable and erroneous claims that distributed photovoltaic ("DPV") systems provide zero value to the grid and to other ratepayers. In making these claims, the Companies disregard the direction of the Commission by failing to recognize the significant potential values of DPV. To that end I present testimony regarding the importance of each of the avoided costs the Kentucky Public Service Commission (the "Commission") has previously ordered the Companies to consider. I offer alternative values for the complete set of potential avoided costs listed by the Commission. I also provide estimates for avoided cost values not specified by the Commission: fuel price hedge value and societal benefits of avoided greenhouse gas emissions. I also testify that the Companies' proposed 1% cap on net metering service ("NMS") customers is unnecessary, and that the Companies can continue to offer NMS-2 bill credits well past the 1% threshold.

Regarding the EHLF tariff, I note the need to ensure a fair balance of risks and potential rewards. As proposed by the Companies, ratepayers take on risks without opportunity for rewards. I question the rationale of eligibility requirements regarding minimum load and load factors, as they preclude small yet relevant loads and thus risk company disaggregation to avoid regulation. I also recommend strengthened ratepayer protections pertaining to ramp-up period and collateral, and I recommend that the Commission initiate a proceeding to assess cost allocation issues pertaining to EHLF customers.

**Q: Please summarize your recommendations for the Commission.**

A: My recommendations to the Commission are as follows:

- Regarding the proposed changes to Rider NMS-2:
  - Use a complete set of avoided costs for the NMS-2 bill credit. Adopt my estimates unless the Companies can improve on my methods with more transparent and representative data.

I recommend composite all-in NMS-2 export rates for KU and LG&E per Table JF-1.

***Table JF-1: Recommended NMS-2 Export Rates***

| | KU ($/kWh) | LG&E ($/kWh) |
|---|---|---|
| **Total Avoided Costs for DPV** | **$0.1820** | **$0.1789** |

  - Add the fuel price volatility hedge avoided cost values to the Commission's list or avoided cost components for net metering.
  - The Companies should plan for and seek to attain significantly higher levels of DPV, with and without pairing other DER
  - The Companies should continue to offer Rider NMS-2 after the 1% capacity threshold is reached.

- Regarding the proposed Rider EHLF:
  - New loads should not be allowed to skirt their responsibilities. Cost causation principles point to the need to protect all ratepayers for unrecovered costs. The Commission should initiate a new proceeding in which cost causation principles are reexamined in the context of energy served, not contribution to coincident peak, along with other potential cost allocation methods.
  - The eligibility criteria are too loose; smaller loads that contribute to costs should not be excluded from the rate.
  - The Companies ought to facilitate and perhaps require load flexibility.
  - The proposed collateral requirement should be strengthened.
  - The ramp-up period should be capped and separated from the minimum contract term.

**Q: Are you sponsoring any exhibits or attachments to your testimony?**

A: Yes, Exhibit JF-1 is my curriculum vitae, and Exhibit JF-2 is a research report by Drs. Richard McCann, James Fine, and Alec Fleischer, *Jobs and Economic Benefits to Kentucky from DPV, Utility Solar, Natural Gas, And Coal Additional Generation Capacity*.

## III. PROPOSED CHANGES TO RIDER NMS-2

**Q: Please provide an overview of the Companies' applications as they relate to net metering.**

A: The Companies have proposed an update to the export rates for Rider NMS-2 that recognizes only one avoided cost value, for generation energy. This is a significant change from their current NMS-2 rates and results in a dramatic reduction in the value offered NMS-2 customers for exported generation. In fact, DPV provides several benefits that are non-zero in value.

**Q: Do the Companies follow Commission guidance when calculating avoided costs to be incorporated into the proposed NMS-2 tariff?**

A: No.

**Q: What is the fundamental flaw in the Companies' testimony about costs avoided by customers installing DPV?**

A: The Companies claim that DPV produces little or no avoided cost value for generation capacity, transmission, distribution, ancillary services, carbon, and environmental compliance, and the Companies do not evaluate jobs benefits. This oversight conflicts with the principles of physics, economic theory, and intuitive logic, and further ignores a growing canon of regulatory orders, including past Commission precedent, economic studies and real-world examples that demonstrate the potential for DPV to provide significant avoided costs and other economic benefits to ratepayers and society. When evaluating the cost and benefits of DPV, the Commission should consider ratepayers, not utility shareholders, as the primary beneficiaries. Although utility finance is important, it is a subset of broader benefits that extend beyond affordable and reliable electricity service to include environmental and economic benefits such as avoiding the myriad impacts of a coal and gas-fueled generation fleet, and the investments, jobs and companion effects needed for healthy communities. None of those benefits accrue to the financial bottom line, which is the fiduciary benchmark for utility managers. That is why it is the responsibility of the Commission to ensure those benefits flow to ratepayers and residents of Kentucky in exchange for the financial assurances that utility shareholders enjoy.

At current and near-term rates of DPV penetration, these additional values have been recognized by the Commission and incorporated into existing NMS-2 rates. As the scale of

DPV and other distributed energy resources ("DER") grow in coming years, their value will grow as well. This has proven true in several jurisdictions with a range of DPV penetration rates.[1]

**Q: What is lacking in the Companies' testimony?**

A: In addition to not following Commission orders in calculating avoided costs, the Companies lack in their assessment: (1) a willingness to take actions that optimize DPV values and (2) a vision for a future with a large, reliable, connected, responsive fleet of DPV that, in aggregate, can be relied upon to deliver values in the form of avoided costs. Together with other DER or independently, DPV can:

- reduce metered peak loads and associated reserves;
- reduce transmission losses and other systemic inefficiencies;
- avoid regulatory risks associated with regulation of air quality including criteria pollutants and greenhouse gases, cooling water discharge, coal ash disposal, and installation of transmission;
- decarbonize economic activities so as to avoid fossil fuel price volatility; and
- make electricity service more affordable, reliable and accessible for all ratepayers.

The Companies' myopic disposition conflicts with their responsibilities to serve all ratepayers with reliable, environmentally compliant, least-cost electricity.[2] The Companies claim that reliability modeling seeks least-cost solutions, but that is not possible when significant DER and DVP solutions are not included. The Companies' short-sighted

[1] For example, California, Arizona, Hawaii and New York, as discussed and referenced below.
[2] *See* Aneil Kovvali & Joshua C. Macey, *The Corporate Governance of Public Utilities*, Yale Journal of Regulation, 40:2 (2023), downloadable at https://www.yalejreg.com/print/the-corporate-governance-of-public-utilities/.

erroneous conclusions about DPV values may become a self-fulfilling prophecy unless the Commission intervenes on behalf of DPV customers and all ratepayers.

**Q: What else is missing from the Companies' testimony?**

A: The Companies should plan for achieving a high DER scenario that far exceeds what is considered in the 2024 Integrated Resource Plan ("IRP")[3] or the 2025 Certificate for Public Convenience and Necessity ("CPCN") forecasts.[4] The Companies have made advanced metering infrastructure ("AMI") investments that position the grid to massively increase penetration of DER, including DPV, demand response programs, and greater reliance on time-variant pricing. The Companies have Time of Use ("TOU") tariffs in place already.[5]

DER capacities will continue their trend of expansion in Kentucky, as has been observed in other jurisdictions. There will be more electric vehicles ("EVs"), smarter homes (that are essentially thermal batteries), actual batteries, smart appliances, and distributed generation. The Companies must plan for hosting and optimizing these resources, rather than to continue to deny their potential for delivering value to all ratepayers.

**Q: Who would benefit if the Companies executed a broader vision for DPV values?**

---

[3] *Electronic 2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2024-00326 (Oct. 18, 2024) ("2024 IRP").

[4] *Direct Testimony of Charles R. Schram Vice President, Energy Supply and Analysis on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company*, Case Nos. 2025-00113 and 2025-00114, at 5-6 (May 30, 2025) ("Schram Direct") explains that the 2024 IRP and 2025 CPCN load forecasts are derived from the same "2025 BP Load Forecast," also relied on here. *See* 2024 IRP, Vol. I at Section 7.(7).(b).7 (Oct. 18, 2024), beginning at pdf p. 65 for a description of how the Companies developed their distributed resource forecast. Joint Intervenors provided a critical review of this forecast in the whitepaper attached to their comments on the IRP. Case No. 2024-00326, *Initial Comments of Joint Intervenors Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association on the 2024 Integrated Resource Plan of Louisville Gas & Electric Company and Kentucky Utilities Company*, Attach. 1, AEC White Paper at 15-17 (Mar. 7, 2025).

[5] Generally referred to as "time-of-day" or "TOD" rates in the Companies' tariffs where optional. E.g., RTOD-Energy: Residential Time-of-Day Energy Service and TODP: Time-of-Day Primary Service; Cf. RTS: Retail Transmission Service, which also contains TOU rates.

A: All ratepayers would benefit from higher DPV penetration because net benefits exceed costs for both non-DPV customers and the one who invests in DPV. Kentucky also has a large rural population[6] that would benefit significantly from distributed solar PV programs paired with storage to enhance reliability and resiliency.

**Q: What is your recommendation to the Commission regarding the Companies' avoided costs generally?**

A: I recommend a complete overhaul of the NMS-2 costs proposed by the Companies because they erroneously claim DPV provides zero avoided costs of generation capacity, ancillary services, transmission, distribution, environmental compliance, or carbon, and disregard its jobs benefits. Revisiting avoided costs, the Companies ought to (a) heed the Commission's direction and methods approved for use in the 2020 Kentucky Power Company NMS case and prior LG&E/KU NMS proceedings,[7] (b) follow industry best practices as demonstrated in numerous studies, and (c) develop a more comprehensive and reasonable NMS-2 bill credit.

In addition to providing fair compensation in the NMS-2, the Companies should take steps to make installed DPV increasingly valuable by increasing scales, geographic coverage,

---

[6] U.S. Census Bureau, *American Community Survey: Kentucky* (2020), estimated 1,840,000 rural residents in Kentucky, which is over 20% of the state population.

[7] Final Order, *In the Matter of Electronic Application of Kentucky Power Company for (1) A General Adjustment of Its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets And Liabilities; (4) Approval of a Certificate of Public Convenience and Necessity; and (5) All Other Required Approvals and* Relief, Case No.2020-00174 Order (May 14, 2021) and Final Order, *In the Matter of Electronic Application of Louisville Gas and Electric Company for An Adjustment of Its Electric and Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00350 (Sept. 24, 2021).

and pairing of other DER (e.g., EV charging, batteries, energy efficiency) and pricing programs (e.g., TOU rates, demand response).

I recommend that the Companies plan for and seek to attain significantly higher levels of DPV, with and without pairing with other DER. And DERs are already in place: well-insulated buildings are big batteries, and with AMI installed, the Companies can expand/create utility programs that activate and utilize DERs at scales of significance (e.g., big and fast enough to enable the retirement of more-costly coal plants, or minimize the need for new capacity additions).

For example, a significant benefit can be the closure of coal power plants well ahead of the schedule shown in the Companies' 2024 IRP. Expedient closure of coal plants can avoid investments in both operations and maintenance ("O&M) costs, as well as planned capital-intensive projects such as the $100 million liner-replacement project at the Companies' Trimble Station,[8] or selective catalytic reduction additions at Ghent 2 for a cost of $152 million by 2028,[9] or at Mill Creek 2 for a cost of $163 million by 2031[10] (or possibly much sooner.)[11]

Coal and natural gas plant closures are appropriate goals for expanding capacities on the customer side of the meter. The Commission has directed the Companies to develop plans to

[8] *Direct Testimony of Lonnie E. Bellar, Executive Vice President, Engineering, Construction and Generation for PPL Services Cor[]p[o]ration on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company*, Case Nos. 2025-00113 and 2025-00114, at 12 (May 30, 2025)("Bellar Direct").
[9] Direct Testimony of David L. Tummonds, *In the Matter of Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates*, Case No. 2025-00045, at 14 (Feb. 28, 2025) ("2025 CPCN Tummonds Direct").
[10] Case 2025-00045, Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the Commission Staff's Third Request for Information Dated May 23, 2025 , Question 8(b)3-8(b), Attach. 1 at 6 (June 6, 2025) ("CPCN 2025 LGE-KU Resp. to Staff 3-8(b)").
[11] Case No. 2024-00045, Aug. 7, 2025 Hearing Video Transcript ("HVT") at 9:56:45 to 10:05:00 A.M.

justify Advanced Distribution Management Solutions ("ADMS") and Distributed Energy Resource Management Systems ("DERMS").[12] Hosting and utilizing DER ought to be a priority for these advanced grid management systems. On inverter upgrades, it is useful to reiterate that existing systems can be upgraded remotely via software upgrades at low cost to facilitate visibility and dispatchability.

In offering a fair NMS-2 rate, the Companies can also continue to offer it after the 1% threshold is reached without concerns about cross subsidies nor the need to update the NMS rate.

**Q: What is the organization of your testimony addressing Net Metering rates?**

A: After summarizing recommendations, my testimony:

- Critiques the Companies' avoided cost analysis to point out that they follow neither Commission direction nor industry standards,
- Proposes alternative methods to quantify avoided costs created by DPV and fairly compensate DPV customers,
- Demonstrates through industry examples and scholarly research that distributed energy resources (DER) provide significant value to the grid in multiple ways and therefore utility policies/rates that suppress the DPV installations (and other DER) are not in ratepayers' best interests.

---

[12] Final Order, *In the Matter of Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric and Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349 at 2 (Sept. 24, 2021) and Case No. 2020-00350 Sept. 24, 2021 Final Order at 2. (The Commission also found that additional information regarding advanced distribution management solutions (ADMS) and Distributed Energy Resource Management Systems (DERMS) was necessary because of LG&E/KU's plans to spend significant amounts on ADMS and DERMS to address potential issues with a dynamic distribution system, such as voltage regulation, even though the penetration of such resources on LG&E/KU's system is miniscule and there are other, more affordable alternatives to ADMS and DERMS.").

- Demonstrates that a 1% cap on distributed solar is unnecessary. Other states have much higher penetrations of distributed solar because it is deemed to be in the best interest of ratepayers.

***A. Avoided Costs***

**Q: What is missing in the Companies' avoided cost calculations for the proposed NMS-2 rates and their alignment with the Commission's net metering avoided cost categories as ordered in 2020-00174, 2020-00349, and 2020-00350?**

A: The Companies have used the correct list but unreasonable logic to evaluate avoided costs and the Companies have not followed Commission direction.[13] Ongoing research and analyses in support of other DPV bill credit proceedings validates the Commission's previous orders. Industry best practices for evaluating avoided costs have been demonstrated and reviewed by national labs. I refer to those studies now.

**Q: What did Lawrence Berkeley National Laboratory find about avoided costs?**

A: In January 2025, Lawrence Berkeley National Laboratory ("LBNL") published a report comparing over twenty studies of the value of DPV. All found non-zero values for several avoided cost components that the Companies claim have zero value in their jurisdictions.[14]

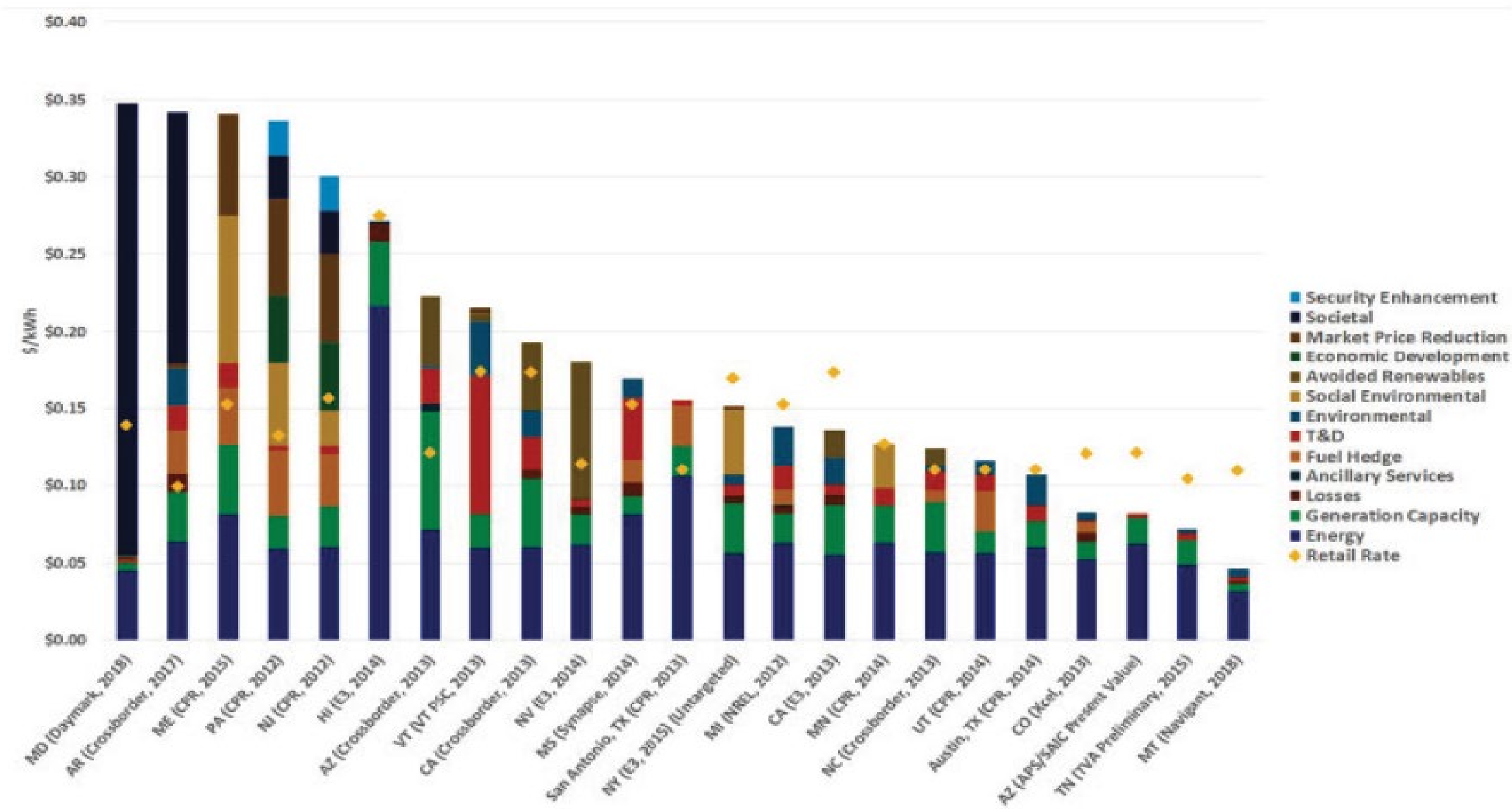
---

[13] Final Order, *In the Matter of Electronic Tariff Filings of Louisville Gas and Electric Company and Kentucky Utilities Company to Revise Purchase Rates for Small Capacity and Large Capacity Cogeneration and Power Production Qualifying Facilities and Net Metering Service-2 Credit Rates*, Case No. 2023-00404, Order at 23 (Aug. 30, 2024) Final Order, *In the Matter of Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric and Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349 (Sept. 24, 2021) and Case No. 2020-00350 Sept. 24, 2021 Final Order at 41-42 (for guiding principles), 42-47 (regarding penetration and interconnection), and 48-58 (for avoided cost rates).

[14] Natalie Mims Frick et al., *Locational Value of Distributed Energy Resources*, Lawrence Berkeley Nat'l Lab'y, at 19 (Feb. 2021), https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf. (no data table provided to recreate this figure).

That research is summarized below in Figure JF-1. Only one study reported a value of solar ("VOS") less than five cents per kilowatt-hour. Five out of 23 studies found values above 30 cents per kilowatt-hour, and all but four were above 10 cents per kilowatt-hour.

***Figure JF-1: Estimated Value of Solar Levels Across Studies from LBNL***[15]




[15] *Id.* at 19, Fig. 11, reproduced here as Figure JF 1: Estimated VoS levels across studies.

**Q: Do you have a recommendation for an NMS-2 export rate that fully represents avoided costs?**

A: Yes.

**Q: What is a reasonable NMS-2 export rate that includes all relevant avoided cost categories?**

A: I recommend composite all-in NMS-2 export rates for KU and LG&E as shown in Table JF-2.

***Table JF-2: Recommended NMS-2 Export Rates***

| **Total Avoided Costs for Customer-Generators** | KU | LG&E |
|---|---|---|
| **Category** | **$/kWh** | **$/kWh** |
| Total Avoided Costs | **$0.1820** | **$0.1789** |

**Q: What are the component values of the recommended NMS-2 export rates?**

A: Table JF-3 shows how I arrived at the composite NMS-2 export rates:

***Table JF-3: Recommended avoided costs by component and totals***

| **Total Avoided Costs for Customer-Generators** | KU | LG&E |
|---|---|---|
| **Category** | **$/kWh** | **$/kWh** |
| Total Avoided Costs | **0.18198** | **0.17895** |
| Total Avoided Costs Without Cost of Carbon | **0.11545** | **0.11241** |
| Total Avoided Cost Without Fuel Price Hedge and Without Reserve Margin | **0.10145** | **0.09841** |
| Total Avoided Cost Without Fuel Price Hedge and Without Reserve Margin Without Cost of Carbon | **0.09471** | **0.09168** |
| Generation Energy | 0.03684 | 0.03684 |
| Ancillary Services | 0.00102 | 0.00105 |
| Generation Capacity | 0.02322 | 0.02322 |
| Risk Hedge Value | 0.01400 | 0.01400 |
| Transmission | 0.01911 | 0.01911 |
| Distribution | 0.00160 | 0.00230 |
| Reserve Margin | 0.00673 | 0.00673 |
| Line Losses | 0.00785 | 0.00409 |
| Cost of Carbon | 0.06653 | 0.06653 |
| Environmental Compliance | 0.00507 | 0.00507 |
| Jobs Benefits | Yes, See Ex. JF-2 | Yes, See Ex. JF-2 |

**Q: Are recommended NMS-2 export rates reasonable even though they exceed retail rates?**

A: Yes. The NMS-2 rates should reflect total avoided costs for ratepayers, not utility investors. The external costs of coal and natural gas generation listed earlier in this testimony (i.e., costs of carbon) add to utility avoided costs to result in NMS-2 export rates that are higher than average retail rates. This is informative because it indicates that the optimal outcome for ratepayers is more investment in DPV, as adding that capacity avoids the substantial costs of additions on the utility side of the meter.

**Q: What is the appropriate way to determine avoided energy costs?**

A: The Companies proposed avoided generation costs be based on a 7-year power purchase agreement ("PPA") for solar. [16] This differs substantially from the industry standard of 20- to 30-year agreements for other generators investing in capital-intensive resources. Customers are not speculators focused on maximizing profits by taking advantage of market volatility and should not be expected to develop sophisticated risk management and hedging strategies for an investment that is truly "set it and forget it" from their perspective. The Companies provided no explanation why ratepayers should be exposed to a shorter term PPA price for technologies that will generate power reliably for multiple decades.

**Q: Why are electricity rates that are dependent on fossil fuel generation more volatile than renewable generation?**

A: There are several reasons why coal, gas and other fossil fuel prices tend to be more volatile than renewable energy sources, including:

*Weather and Natural Disasters*: Extreme weather events, such as floods or droughts, can disrupt mining operations and transportation networks, thus impacting supply and causing price spikes.

*Geopolitical Events*: Events like Russia's invasion of Ukraine have directly affected natural gas prices and volatility, leading to initial price surges followed by subsequent shifts as markets adjusted to sanctions and altered trade flows.

*Economic Growth*: The economic performance of major coal-consuming regions, particularly China and India, is a significant factor. Slower economic growth in these regions can decrease coal demand, while faster growth can lift prices.

[16] Case No. 2020-00174, May 14, 2021 Final Order at 23.

*Energy Security Concerns*: Easing energy security concerns, which can be influenced by factors like natural gas prices, can reduce demand for coal and contribute to price volatility.

*Power Generation Dynamics*: The reliability of coal-fired power plants, especially older fleets in some regions, can affect demand by increasing the probability of outages. Customers are likely to rely on electricity if the grid becomes less reliable.

*Supply and Demand Balances*: Periods of supply outgrowing demand, as seen in 2023, can lead to significant price downturns. Conversely, tight supply can support prices.

*Government Policies*: Policy changes, such as the decontrol of coal prices in China or amendments to electricity acts, can significantly influence market dynamics and price stability. [17]

**Q: What are the consequences to ratepayers of this heightened volatility?**

A: This volatility increases risk to ratepayers who reduce their investment in other productive goods and services in response to higher risk. Presented here is a partial list of the most important consequences.

*Increased Risk for Energy Users*: Buyers face a greater risk of being caught in price spikes, especially those on short-term contracts.

*Pressure on Producers*: Significant price declines, particularly after periods of high volatility, can create economic pressure on coal producers.

*Market Uncertainty*: Greater volatility in energy markets means longer periods where prices are at their crests, increasing the time-to-market risk for those needing to renew contracts.[18]

[17] Suraj jha, *Coal Price Trend Overview: Market Dynamics, Historical Data & Regional Analysis*, Price Trend Update (Apr. 28, 2025), https://www.linkedin.com/pulse/coal-price-trend-overview-market-dynamics-historical-data-suraj-jha-t9jmc.
[18] *Id.*

Given their aversion to speculation and desire for bill stability, ratepayers would benefit from fuel price stability and affordability. It is that desire that is an important driver in investing in DPV. Planning to continue to rely on coal and natural gas burdens ratepayers with risks that can be avoided with a renewable energy supply regime. In addition to price risks, continued reliance on coal will mean continued environmental and public health costs, and risk of increasing compliance costs.

**Q: What did the Companies miss in excluding price volatility?**

A: In revisiting avoided energy costs, the Companies ought to expand the analysis of energy price uncertainty and to estimate fuel price hedge avoided cost values, which I address later in my testimony. The latest forecast from the U.S. Energy Information Administration ("U.S. EIA") is that natural gas prices will increase dramatically in the next year.[19] The U.S. EIA *Short Term Energy Outlook* forecasted Henry Hub price average will be $3.60/MMBtu in 2025 and $4.30/MMBtu in 2026.[20] Though five price scenarios were studied, they did not reflect (a) higher than expected rising natural gas prices, and (b) and the benefit from decoupling of electricity and fossil fuel prices by relying more heavily on renewables (on both sides of the meter).[21]

**Q: Do you recommend the Commission add an avoided cost for fuel price volatility?**

A: Yes. I recommend the Commission also contemplate including an energy price risk hedge benefit created by using renewables to meet incremental load.

---

[19] U.S. Energy Info. Admin., *Short Term Energy Outlook* (released Aug.12, 2025), https://www.eia.gov/outlooks/steo/report/natgas.php.
[20] *Id.*
[21] *See* Case No. 2025-00045, Direct Testimony of Stuart A. Wilson Director, Energy Planning, Analysis and Forecasting on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company, Ex. SAW-1 at 62 (Feb. 28, 2025).

Although the Commission has not directed the Companies to include the Energy Price Risk Hedge avoided cost, omitting it would fail to account for this "pecuniary externality." Fossil fuel energy price shocks have occurred about twice per decade historically, and ratepayers are exposed to that volatility when the generation is powered by natural gas.[22] The Companies' power supply is heavily dependent on natural gas and coal, making ratepayers highly vulnerable to fuel price volatility.

A study from Rocky Mountain Institute (2012) sets out one method for calculating the volatility cost of natural gas-powered electricity, which is the primary source for energy setting the market clearing price in the PJM market.[23] The study found the hidden cost of market volatility in market gas price appears to be \$1.50 to \$2.50 per MMBtu. Assuming a thermal efficiency or "heat rate" for the marginal use of gas in the electricity market of 7,000 British thermal units per kilowatt-hour ("BTU per kWh"), equals a benefit of an additional \$0.0105 to \$0.0175 per kWh provided by DPV. Using the average of these is **\$0.0140/kWh** for calculating the avoided cost of energy price risk.

**Q: What do you use for avoided energy costs in your alternative calculations?**

A: Despite the concerns detailed above, I use the avoided cost estimate provided in Witness Schram's testimony for a fixed tilt solar 7-year PPA.[24] This is a conservative value because the Commission directed Kentucky Power to treat DPV like any other generation project in terms of full-lifetime costs and benefits,

---

[22] James Fine et al., *The upside hedge value of California's global warming policy given uncertain future oil prices. Energy Policy*, Vol. 44, 46-51 (May 2012).
[23] Lisa Huber, *Utility Scale Wind and Natural Gas Volatility*, Rocky Mountain Institute (July 2012), https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_2012-07_WindNaturalGasVolatility.pdf.
[24] Schram Direct, Ex. CSR-6 at 5, Tbl.4.

> A utility makes economic decisions that consider the entire life of a project, and such long-term analysis should also apply to an eligible customer-generator. Given that the typical warranty provided by a solar panel manufacturer is 25 years, this would be an appropriate analysis period for Kentucky Power's net metered customers. A long-term approach ensures unbiased evaluation of system resources, ensures ratepayers are paying fair value for avoided future costs, and compensates eligible customer-generators fairly.[25]

In the context of the Companies proposal, avoided costs would be more appropriately based on a 20-year PPA. The Commission agreed in the 2020 LG&E-KU NMS case.[26]

**Q: What is the appropriate way to value for avoided generation capacity costs?**

A: While the Commission has agreed "that, when capacity is not needed, the avoided capacity cost rate can be zero," it has properly stated that "[t]he applicant utility bears the burden to demonstrate the reasonableness of zero avoided capacity costs," and ordered that avoided costs "should accurately reflect LG&E/KU's own generation system and future capacity needs."[27]

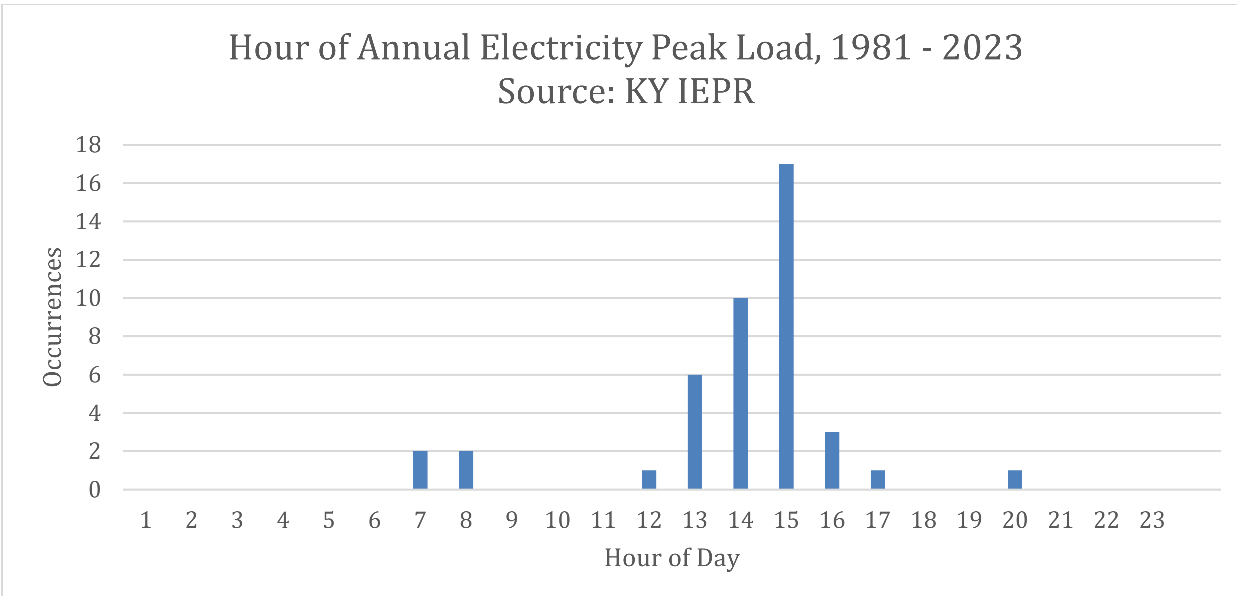
**Q: Do DPV systems provide generation during coincident system peak hours?**

A: Yes. LG&E/KU IRP data for the last 43 years (through 2023) indicate that DPV production output coincides with system metered peaks for most of the years.[28] Figure JF-2 shows that 38 of 43 annual system peaks occurred between noon and five PM, with 36 of those 38 between 1 and 4pm. DPV output aligns with these system peaks, so it is reasonable to conclude that it avoids the need for additional peak generation capacity.[29] Notably the vast

[25] Case No. 2020-00174, May 14, 2021 Final Order at 23 (citation omitted).
[26] Case No. 2020-00349 and 2020-00350 at 49 ("As identified by intervenors, the $0.02319/kWh that LG&E/KU proposes to offer NMS 2 customers is lower than the energy rate LG&E/KU proposed for QFs electing the 20-year rate option. Given that customer-generation is a long-term investment, which the Commission has treated as 25 years in its rate component calculations, it is reasonable to offer customer-generators the longer-term energy price rather than LG&E/KU's calculated 2-year PPA price.").
[27] Case No. 2023-00404, Order at 20, 21 (Aug. 30, 2024).
[28] 2024 IRP and witness Schram workpapers (tblActualHistoricalLoad WBC 8.13.25.xls).
[29] *Id*.

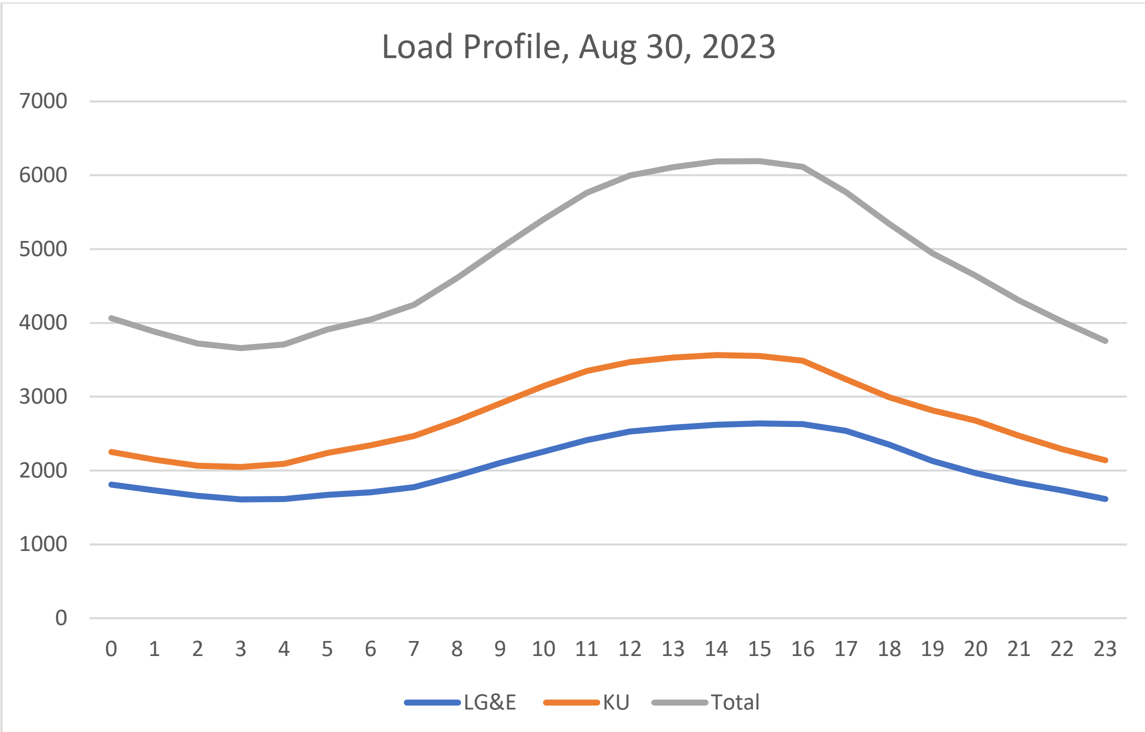
majority of peak loads have occurred between 1 pm and 3 pm EST, which coincides closely with the peak output of DPV.

***Figure JF-2: Distribution of Peak Hours***




Though a few annual system peaks have been observed in winter seasons, the system load curve for the peak day (August 30) in 2023, Figure JF-3, also coincides with the timing of DPV output.

***Figure JF-3: Example Daily Load Profile (Source: Witness Schram workpapers)***




In terms of reliability, coal generation has a 12% chance of being offline and output falls to zero during offline events.[30] By comparison, the fleet of DPV is rarely offline simultaneously so total output never falls to zero during the hours of expected solar generation. The law of large numbers indicates that the likelihood of a fleet of DPV going offline at the same time is very low compared to a few large-scale generators. Furthermore, grid generation is also dependent on transmission line reliability, but DPV is not.

**Q: Have the Companies demonstrated that generation capacity is not needed?**

A: No. In fact, to the contrary the Companies have repeatedly stated recently that it faces an imminent capacity shortfall, and recently applied for almost 1,700 MW of additional

[30] Emergency Preparedness Partnerships, *NERC Says Forced Outages are at Historically High Levels*, https://emergencypreparednesspartnerships.com/nerc-says-forced-outages-are-at-historically-high-levels/, (last visited Aug. 29, 2025).

generating resources, plus additional capital investments to keep another 500 plus MW resource afloat.[31] While the Joint Intervenors have disputed the extent of that capacity shortfall,[32] the burden remains on the utility to show that it has ***no*** capacity need. To propose $3.7 billion in capital investments related to capacity in one case, and state that it has no avoided capacity costs in the next a mere few months later, is hypocritical of the utility, and should raise a red flag for the Commission for consistency across filings.

**Q: How do you suggest avoided generation capacity costs be calculated?**

A: As directed by the Commission in the Kentucky Power case,[33] I calculate the Net Cost of New Entry (Net CONE) using the following the Companies' reported values:

- avoided capacity in 2026 ($125.66 $/kW-year)
- weighted capital cost (6.56%)
- fixed solar capacity factor (15.5%)
- annual solar generation (1,458 hours)
- effective load carrying capacity (54%)[34]

My calculation discounts avoided capacity cost by DPV's Effective Load Carrying Capacity (ELCC, 54%), reflects net present value using the Companies' weighted cost of capital, discounts again for fixed tilt solar capacity factor (15.5%), and then divide by solar generation (kWh/yr). I determined the ELCC using the NREL PV Watts calculated average

---

[31] Case No. 2025-00045, Joint Application at 1 (Feb. 28, 2025).
[32] *See*, *e.g*., Case No. 2025-00045, Testimony of Elizabeth A. Stanton, PhD on Behalf of Joint Intervenors Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association (June 16, 2025) ("2025 CPCN Stanton Direct").
[33] Case No. 2020-00174, May 14, 2021 Final Order at 29 ("The Commission finds that the capacity price should be replaced with the Net CONE values specified in Kentucky Power's COGEN-SPP Tariff an average of $7.57/kW month, or $249/MW-Day. Net CONE reflects an approximate capacity market equilibrium and therefore better reflects long-term avoided capacity value.") (citations omitted).
[34] 20250402_LAK_AvoidedCapacityCost_2025RateCaseCSR.

output during system peak hours in August for Louisville was 54%. The result is an avoided capacity cost of **$0.0232/kWh**.

The Commission previously noted in the Companies' last NMS-2 adjustment case that

> [t]he applicant utility bears the burden to demonstrate the reasonableness of zero avoided capacity costs, and it appears that LG&E/KU proposed zero avoided capacity costs based on the Commission's decision in its 2020 rate case rather than its actual avoided costs.[35]

Furthermore, the Commission added,

> Additionally, considering avoided costs are long-term in nature, the Commission notes that the long-term avoided costs, or 7-year contracts, should accurately reflect LG&E/KU's own generation system and future capacity needs. LG&E/KU argued that, because QF technologies do not have similar operating characteristics and the avoided capacity cost is intended to be a capacity-only value, it is not appropriate to use the cost of an NGCC in the calculation of avoided capacity cost. However, **the Commission disagrees with LG&E/KU's argument and notes that LG&E/KU, in November 2023, received Commission approval to retire Mill Creek 1 & 2 and begin construction of the Mill Creek 5 NGCC**. LG&E/KU anticipate that the in-service date for Mill Creek 5 would be 2027. Therefore, the Commission notes that **it is appropriate to utilize an NGCC for capacity values and costs** considering the capacity values should reflect the actual resource generation that LG&E/KU is constructing/planning to meet their capacity needs. Additionally, the Commission notes that while QF's may not have similar operating characteristics, QF's invest in technologies like solar, wind, or small-scale cogeneration, which offer significant environmental, and reliability benefits that LG&E/KU should take advantage of to reduce greenhouse gas emissions or diversify its energy supply to reduce market volatility to its customers.[36]

Figure JF-4 shows Net CONE calculations for reliability-focused capacity additions for several system operators, including Kentucky-adjacent MISO and PJM. Except for the CAISO value as an outlier, these values are consistent with the $125 per KW-year used by the Companies.

[35] Case No. 2023-00404, Aug. 30, 2024 Final Order at 20.
[36] *Id.* at 21 (citations omitted).

DPV not only avoids capacity need, but it also avoids transmission losses and reserve margin requirements. Therefore, the value of DPV avoided generation capacity is greater than central station generation requiring transmission.

***Figure JF-4: Summary of ISO and RTO Net CONE Capacity Values***[37]

| | BA-Specified "Firming" Source | ELCC Values[2] | Net CONE[1] ($/kW-month) | Selected Market Commentary |
|---|---|---|---|---|
| MISO | Natural Gas Peaker | Solar: 39%<br>Wind: 26% | $10.03 | • In March 2024, MISO adopted the FERC Reliability Availability and Need ("RAN") seasonal capacity construct for wind and solar resources<br>• Seasonal wind accredited capacity values are 18.1% for summer, 18.6% for fall, 53.1% for winter and 18.0% for spring<br>• Solar capacity values are 50% for all seasons except winter, which is 5% |
| CAISO | 4-Hour Lithium-Ion Battery | Solar: 7%<br>PV + Storage[3]: 41%<br>Wind: 12% | $18.92 | • Increasing levels of solar penetration in CAISO have shifted peak demand later in the day, reducing the ELCC value for solar<br>• CAISO significantly reduced ELCC values for 4-hour battery storage systems, driven by significant growth in 4-hour storage capacity |
| SPP | Natural Gas Peaker | Solar: 51%<br>Wind: 20% | $8.38 | • SPP published seasonal accreditation values based on 2024, assigning separate values to resources for summer and winter seasons<br>• Summer wind and solar contributions are 15.2% and 25.5%, respectively, whereas winter values shift to 39.1% for wind and 62.2% for solar |
| PJM | Natural Gas Peaker | Solar: 12%<br>PV + Storage[3]: 33%<br>Wind: 38% | $10.29 | • PJM adopted a new, marginal ELCC methodology to begin in the 2025/2026 delivery year that reduces the reliability value of highly correlated resources, such as solar and short-duration storage[4]<br>• The update is expected to better capture expected resource performance during system peak |
| ERCOT | Natural Gas Peaker | Solar: 38%<br>Wind: 25% | $9.92 | • ERCOT maintains notably high ELCC values despite having the highest renewable penetration by capacity of the U.S. regulatory markets<br>• ERCOT updates its capacity scheme every three years; the most recent publication was December 2022 |

[37] Lazard, *Levelized Cost of Energy+ (LCOE+)*, at 28 (June 2025) ("Lazard Report"), https://www.lazard.com/research-insights/levelized-cost-of-energyplus-lcoeplus/. Chart is reproduced here.

**Q. Did the Companies follow Commission direction in calculating avoided transmission costs?**

A: No.

**Q: What is the appropriate way to determine avoided transmission costs?**

A: The Commission directed the Companies to calculate avoided transmission costs and established a benchmark value for 2020.[38] The Companies claim the small amount of existing and forecasted DPV capacity has no value in reducing transmission infrastructure costs. Yet the Companies are planning over $1 billion in transmission system investments through 2026.[39]

There is a misunderstanding of what drives transmission investment (versus distribution which is more demand driven.) DPV can displace transmission investment because transmission is built to deliver generation energy and capacity and is driven by additions of generation, not increases in demand. Building transmission for increased demand without having excess or new generation at the other end of the line is an illogical investment. Demand can drive increases in generation which indirectly increases transmission investment, but more often generation is added either to plants to replace those that have been retired or in the form of remote renewable energy that comes with a lower cost than existing fossil generation.

---

[38] Case Nos. 2020-00349 & 2020-00350, Sept. 24, 2021 Final Order at 51-52 ("The Commission finds it reasonable to modify the Minnesota VOS approach to estimate an avoided transmission capacity cost. . . . Based on the approach described above, the Commission finds the fair, just and reasonable avoided transmission capacity cost to be $0.00732.").

[39] Direct Testimony of Elizabeth J. "Beth" McFarland, Vice President, Transmission on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company, Case Nos. 2025-00113 and 2025-00114, Table at 26 (May 30, 2025) ("McFarland Direct").

New transmission is needed to convey *energy* from new plants in new locations. Specifically, the Companies are planning new transmission projects for expansion of their own generation resources, including Mercer Solar, Mill Creek 5, and the Battery Energy Storage System for the Brown Generating Station."[40]

The Companies have not evaluated the potential to avoid these (or similar future) investments with high DER scenarios. This lack of evaluation is particularly irresponsible when it is proposing transmission expansion costing $100 million and another $170 million for connecting new customers.[41]

The Companies point to anticipated growth in load from data centers and other manufacturing projects along with new load from building and transportation electrification. As these resources put new demands on the grid, the presence of DPV, combined with new DER strategies and programs, such as dynamic pricing and demand response programs that deliver VPP-scale resources, the need to upgrade transmission may be mitigated or exacerbated, depending on how the DER are treated. If connected and motivated (e.g., price signals with technologies like smart thermostats and EVs with scheduled charging), DERs can be optimized. If instead treated as dumb and disconnected, then DER resources can add cost burden to the grid relative to business as usual operations.

The Commission should direct the Companies to take steps to reduce the chance that DER will be underutilized. It is the responsibility of the Companies to take actions that increase the availability and value of DER rather than to ignore them in excessively expensive expansion plans.

---

[40] Schram Direct at 23.
[41] McFarland Direct, *supra* note 39, table at 26.

The Companies' witness Waldrab's statement that "Rider NMS-2 customers have exclusively installed solar generation, which affects the timing and conditions under which they can generate"[42] makes two important errors. The first is that DPV output is correlated strongly with the peak loads of the DPV and as a portfolio is highly reliable. The second is that on a forward-looking basis, NMS customers may eventually add dispatchable batteries to pair with DPV (and many already do have batteries).

Even more likely in the near term, NMS customers can be incented to be thoughtful about using DPV to aid storage strategies like pre-cooling buildings and commercial customers joining (an expanded) Curtailable Service Rider program. Load shifting potential will be increasing as customers also adopt batteries and electric vehicles. Already there are examples of "non-wires alternatives" where utilities have avoided costly transmission or distribution infrastructure in favor of DER.[43]

**Q. How do you recommend the Commission calculate avoided transmission costs?**

A: Using transmission rates for LG&E-KU from 2016 through 2021, I extrapolated those values to 2025 based on an 11% annual rate of increase. I divided by solar production hours (kWh per year) and ELCC (54%) during peak hours. I determined the ELCC using the NREL PV Watts calculated average output during system peak hours in August for Louisville.[44] My result is that avoided transmission costs for DPV is **$0.0191/kWh**.

---

[42] Case No. 2025-00113 and Case No. 2025-00114, Direct Testimony of Peter W. Waldrab Vice President, Electric Distribution on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company, at 40 (May 30, 2025) ('Waldrab Direct").

[43] For New York, *see* Joint Utilities of New York, *Non-Wires Alternatives (NWA): Opportunities and Solicitations*, https://jointutilitiesofny.org/nwa-opportunities (last visited Aug. 28, 2025). For Oakland, California, *see* PG&E, *Oakland Clean Energy Initiative* (Feb. 15, 2028), https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/p/6442456241-pge-oakland.pdf.

[44] Nat'l Renewable Energy Lab'y, *PVWatts Calculator*, https://pvwatts.nrel.gov/ (last visited Aug. 28, 2025). Average output for August at 2 p.m. is 2194 watt for a 4000 watt system, which is 54.9% of rated capacity. August 2 p.m. hour is the most common peak hour in LG&E/KU's territory.

By comparison, Commission directed the Companies to use $0.00732/kWh in 2020.[45] Inflating this values to 2026 using the consumer price index ("CPI") yields $0.0091/kWh in 2026. Nevertheless, I recommend using the avoided costs that I calculated using transmissions service rates ($0.0191/kWh).

**Q: Did the Companies follow Commission direction in calculating avoided distribution infrastructure costs?**

A: No.

**Q: What is the appropriate way to determine avoided distributed infrastructure costs?**

A: The Commission directed the Companies to calculate avoided distribution costs and established a benchmark for 2020 at $0.00129/kWh for LG&E and $0.00185/kWh for KU, based on a reduction in future carrying costs for distribution infrastructure additions.[46] In the absence of better data and analysis, the Companies ought to use benchmarks inflated to the present, using the Consumer Price Index (CPI 125% from 2020 to 2025), which equal **$0.0016/kWh and $0.0023/kWh for LG&E and KU**, respectively.

The Companies acknowledge DPV potential:

> [I]t is certainly possible they could [result in avoided distribution capacity]. Other utilities, including Companies' affiliate utility in Pennsylvania, PPL Electric Utilities, have demonstrated that distributed energy resources can enable avoidance of distribution capacity cost when (1) distributed energy resource penetration is significant and (2) the serving utility can control and dispatch distributed energy resource functions. When distributed energy resources are dispatchable, the serving utility can use them, for example, to time-shift peak demand on circuits nearing capacity to offset the need for capacity upgrades. Dispatchable distributed energy resources can also be used to manage reactive power, reducing the need for investment in voltage regulation and improving circuit capacity.[47]

[45] Case Nos. 2020-00349 & 2020-00350, Sept. 24, 2021 Final Order at 51-52.
[46] *Id*. at 54.
[47] Waldrab Direct at 41.

Yet, the Companies are not planning to facilitate the DER utilization. The lack of action is particularly egregious because the Commission directed the Companies to justify their costs of ADMS and DERMS systems.[48] Further, marginal distribution costs must be calculated on a long-term basis, that is 30 to 40 years, that reflects the book life of the assets. Even using the deferral method requires that it be calculated based on a lifetime cost of near-term investment and then of a more distant period and then calculating the difference in net present value costs between the two cases.

**Q: Did the Companies follow Commission direction in calculating avoided ancillary service costs?**

A: No.

**Q: What is the appropriate way to determine avoided ancillary service costs?**

A: The Commission directed the Companies to calculate avoided ancillary service costs and established a benchmark of $0.00082/kWh for LG&E and $0.00084/kWh for KU.[49] The Companies claim that the value is zero. In fact, DPV reduces peak loads without requiring additional reserve margins and without line losses, thereby reducing the need for ancillary services. In the absence of additional analysis, the Companies should use the benchmark value inflated to present day.

The Companies say that reactive power and other ancillary service costs are encompassed within generation costs. This is only true if no additional costs are incurred to provide VARs. These costs are in addition to those for reserve margins as they also include unloaded capacity used to meet load ramping.

[48] Case Nos. 2020-00349 & 2020-00350, Sept. 24, 2021 Final Order at 2; Case Nos. 2020-00349 & 2020-00350, June 31, 2021 Order at 33-34, 66.
[49] Case Nos. 2020-00349 & 2020-00350, Sept. 24, 2021 Final Order at 53-54.

**Q: How do you recommend the Commission set avoided ancillary** service **costs?**

A: The Commission direct the Companies to use values calculated as a percentage of avoided generation capacity costs. I inflated those values – $0.00082/kWh for LG&E and $0.00084 for KU – to 2025 values using the Consumer Price Index (CPI, 125% from 2020 to 2025) to arrive at **$0.00102/kWh for LG&E and $0.001045 for KU**.

**Q: Did the Companies follow Commission direction in calculating environmental compliance costs?**

A: No. The Companies did not estimate avoided environmental compliance costs. By comparison, the Commission found "that Kentucky Power erred in not including an avoided environmental compliance cost estimate within the NMS II export rate."[50] Similarly, in the 2020 LG&E and KU cases, the Commission developed an estimate based on the compliance costs for coal combustion residuals (CCR) and effluent limitations guidelines (ELG) project implementation costs.[51]

**Q: What is the appropriate way to determine avoided environmental compliance costs?**

A: The Commission directed the Companies to include avoided environmental compliance costs. For ratepayers, environmental costs are real. The Companies are planning to continue to operate generation that produces significant environmental risks. The Companies claim these costs are part of generation costs. I disagree because there are really two types of costs associated with power plant emissions: (a) social costs of pollution, including morbidity and mortality caused by coal-source particulate pollution and the effects of climate change, and (b) regulatory responsibilities to mitigate potential harms to human health and the environment.

---

[50] Case No. 2020-00174, May 14, 2021 Final Order at 36-37.
[51] Case Nos. 2020-00349 & 2020-00350, Sept. 24, 2021 Order at 56-57.

As in the 2020 cases, real environmental mitigation costs can be identified. In fact, emissions control installation – selective catalytic reduction ("SCR") – is being planned for 2028 as a discrete investment cost of $150 million for the Companies' Ghent 2 unit.[52] Additional investment in SCR for Mill Creek 2 may be required if the Commission approves the stipulation in Case No. 2025-00045 that involves extending the life of that unit.[53] To the extent that emissions controls are already in place, the costs are also embedded. But some legacy generation, such as Ghent 2 and Mill Creek 2, have managed to avoid installing controls. Therefore, environmental compliance costs are not captured entirely within power prices, and new compliance costs could be avoided with higher levels of DPV. The $150 million cost for SCR at Gent 2 points to an environmental compliance cost. Assuming Ghent 2 continues to produce approximately 2,700 GWh/Year for 20 years, it would have a lifetime production of 54,000 GWh at a cost of **$0.0051 $/kWh** when discounted using the Companies weighted average cost of capital (6.56%)**.**

Scaling DPV and other DER can lead to the closure of coal generation without incurring environmental compliance costs.

In addition to SCR costs, the Companies continue to bear significant regulatory risk by relying on coal-powered generation. The Companies have a responsibility to reduce risks for ratepayers, yet they plan to continue to operate coal through 2040.

Air pollution emissions harm the environment and humans. Kentucky ranks 24th in nation in load served but is 3rd for emissions rate (lbs. carbon dioxide per MWh of electricity

[52] Case No. 2025-00045, Joint Application at 12; Case No. 2025-00045, Tummonds Direct at 14.
[53] Case No. 2025-00045, Aug. 07, 2025 HVT at 9:56:45 to 10:05:00 A.M.

production).[54] Consequently, Kentucky absorbs the environmental and public health costs of burning "cheap" coal in archaic furnaces. Alternatives like DPV avoid the noxious gases and mining impacts of coal, while supporting a more vibrant economy. (See attached Exhibit 2 comparing coal and rooftop solar in terms of jobs and local investments.)

DPV avoids these emissions, which accumulate to cause social costs that are well-documented by the U.S. Environmental Protection Agency.[55] Paired with batteries and other DER, DPV can be even more effective at avoiding emissions, reducing environmental costs and shifting load away from peak hours.

In addition, coal plants must meet increasing coal ash disposal requirements with larger costs, and fossil generators must comply with clean water regulations for cooling water discharges.[56]

**Q: How is the Companies' reserve margin accounted for in your calculations?**

A: I multiply generation capacity costs by the reserve margin, which peaks at 29% in the Companies workpapers[57] to arrive at **$0.0067/kWh**.

[54] U.S. Energy Info. Admin., Form EIA-860, *Annual Electric Generator Report*; U.S. Energy Infor. Admin., Form EIA-861, *Annual Electric Power Industry Report*; U.S. Energy Info. Admin., Form EIA-923, *Power Plant Operations*.
[55] *See* U.S. EPA, *Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, Docket ID No. EPA-HQ-OAR-2021-0317 (Nov. 2023), ("EPA Social Cost Report"), https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf.
[56] *See* U.S. EPA, Steam Electric Power Generating Effluent Guidelines - 2024 Final Rule. 40 C.F.R. Part 423 (2024), https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2024-final-rule (for effluent guidelines); *see also* U.S. EPA, *Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities*, 80 Fed. Reg 21,302 (Apr. 2015), https://www.epa.gov/coal-combustion-residuals/coal-ash-rule (for disposal requirements).
[57] Case No. 2025-0045, Wilson Direct, Ex. SAW-1 at 23, tbl.7.

**Q: How are line losses accounted for in your calculations?**

A: I multiply transmission line loss rates by avoided costs for generation capacity, generation energy, energy price hedge value, reserve margin, transmission, distribution and ancillary services because line losses increase each of these cost components as power is transmitted from utility-scale plants to customers' premises where DPV are installed. Line loss differences between KU and LG&E are the reason I have recommended different NMS-2 export rates. I find KU and LG&E avoided line losses costs are **$0.008/kWh and $0.0042/kWh**, respectively.

**Q: Did the Companies follow Commission direction in calculating avoided carbon costs?**

A: No. The Companies claimed no avoided carbon costs because "there is currently no carbon price for the Companies' carbon emissions."[58]

**Q: How do you recommend the Commission calculate the avoided cost of carbon?**

A: To estimate the carbon cost, I used a conservative approach that averaged the cost of carbon capture and storage for natural gas and coal generation ($126/ton), which converts to $0.067/kWh using a natural gas generator heat rate of 10,000 Btu/kWh.[59] This is found to be a conservative estimate when compared to formulas using the U.S. EPA estimates for the social costs of carbon pollution.[60]

**Q: Did the Companies follow Commission direction in calculating jobs benefits?**

A: No. The Companies did not follow Commission direction and did not evaluate job benefits. Despite Commission direction, the Companies did not use the NREL JEDI model. So I worked with a colleague to do so.

---

[58] Schram Direct at 38.
[59] EPA Social Cost Report *supra* note 55 at 78. Table 3.1.1.
[60] *Id.* at 74-75.

**Q: What is the appropriate way to evaluate jobs benefits?**

A: The Commission directed the Companies to include jobs benefits in their avoided costs calculations.[61] Though jobs are not within the boundaries of utility finance, employment is a critical element of ratepayers' well-being as it portrays broader economic conditions. Just as with environmental impacts and costs of compliance, these benefits are external to the direct activities in using power delivered by the utilities. The Commission's role is to not only ensure that the investor-owned utilities are financially viable, but also to enhance the wellbeing of ratepayers who also are consumers and workers in the broader economy. The utility does not operate in isolation so the Commission should consider how it relates to the economy as a whole.

Jobs related to DPV are calculatable, as shown in attached Exhibit JF-2. In an example for the entire state, again using JEDI modeling, McCann (2024) estimated the economic benefits of solar in Kentucky.[62]

***B. Value to the Grid***

**Q: Does the NMS-2 bill credit rely on subsidies from other rate classes?**

A: No. The premise of the "cost shift" argument that asserts saving energy by one customer causes higher rates for other customers relies on an interpretation of regulation whereby utility shareholders are shielded from suffering any financial losses caused by consumers turning elsewhere to find their energy services. Under this flawed rubric, each customer has an obligation to pay a share of the utility's fixed and stranded costs. When a customer

[61] Case Nos. 2020-00349 & 2020-00350, Sept. 24, 2021 Final Order at 58.
[62] Ex. 1, Dr. Richard McCann, *The Economic Benefits of Rooftop and Utility Solar in Kentucky* (March 2024), attached to the Corrected Prepared Direct Testimony of Richard McCann, Ph.D on Behalf of Joint Intervenors Kentucky Solar Energy Society and Kentuckians for the Commonwealth, Case No. 2023-000413 (June 7, 2023).

reduces their usage and their electricity bill, they are shirking this obligation according to the cost-shift argument.

Using this underlying rationale that utilities are guaranteed to recover their costs once approved by the PSC and FERC, whether a customer-installed resource has a cost more or less than the social marginal cost is irrelevant unless that marginal cost is higher than the retail rate. Based on this reasoning, the customer owes the full amount of the retail rate and only receives a credit for saving energy that cannot exceed the marginal cost. The customer still owes the difference between the retail rate and the marginal cost, and other customers must pick up that foregone sales revenue from the savings. Once a utility is authorized to collect a set amount of revenues, a customer has no escape from the corporate burden under this rationale.

When faced with declining sales and revenues, every other business cannot simply demand that customers make up the difference between the business' current costs and its falling revenues. The business, instead, must either cut costs or provide a better service or product that attracts back those or other customers. The innovation motivated by this "creative destruction" as Joseph Schumpeter described it is at the core of the benefits we accrue from a market economy.[63] Hinder that process and we get stagnation. The phased deregulation of the U.S. electricity market started with the 1978 Public Utilities Regulatory Policies Act ("PURPA") and is an important example of innovation unleashed by removing the utilities' ability to veto customers' investments in their own resources. Without PURPA and the subsequent reforms, we would never have had the technological revolution that both

[63] Joseph Schumpeter, *Capitalism, Socialism and Democracy*, Chs. VI, VI. (3d ed. 2008).

gives lower cost natural gas and renewable energy resources, and customers more control over their own energy use.

The presumption that ratepayers are obligated to reimburse the utility for all sales losses eliminates the ability to use market discipline through consumer choice to control rates (except moving out of state or to a municipal utility area). The only alternative means of containing utility rates and mitigating bills remaining is via regulatory action by the Commission and the Federal Energy Regulatory Commission ("FERC").

**Q: Are there other methods available to the Companies to allow for immediate grid modernization?**

A: The Companies have AMI data that can be used to understand customer potential for demand response and DPV, and to calculate potential values at much higher scales of penetration and utilization. This information can be used by the Companies to develop customer-first plans that remain robust in the future.

**Q: Are there other examples of utilities using such tools to achieve grid modernization on a least-cost basis?**

A: Other jurisdictions are already building solar plus batteries as the least-cost, preferred new capacity in 2025. Yet the Companies believe NGCC will still be preferential in 2040 despite all price trends suggesting otherwise. Demand response at scale is being demonstrated at NGCC scales, and larger.

Pacific Gas & Electric ("PG&E") recently ran a test on the demand response programs managed by third-party vendors. On July 29, 2025, for two hours, from 7 pm until 9 pm, residential batteries were aggregated into a virtual power plant. Working with Tesla, Tesla batteries were dispatched to supply an average of 535 MW to all three IOU service territories in California.[64] Battery and solar generation costs are declining whereas fossil fuel prices are rising, and this trend will only continue.

**Q: Is the NMS-2 bill credit a fair way to compensate DPV owners?**

A: If corrected to conform with previous PSC directives, yes. Once the Companies adopt bill credits that reflect avoided costs accurately, the NMS-2 bill credit will be a fair way to compensate customer-generators. As well, because cross subsidies are minimized, the Companies can continue to offer the NMS-2 tariff well past the 1% threshold.

Facilitating DPV adoption is in the best interests of all ratepayers because significant non-monetizable benefits accrue to non-NMS customers.

Potential for cost shifts from NMS customers to non-NMS customers is small given that there are significant non-zero avoided costs. Currently, DPV penetration is low, but it is forecasted to expand rapidly (in the right conditions). Once DER are significant enough to, for example, avoid alternative investments in generation and transmission, values will be more significant. Those values should be part of the Companies' plans, rather than ignored.

The Companies should be doing opposite of denying the values of DER; rather, they should be making every reasonable effort to optimize existing DPV resources, and to utilize the growing endogenous capabilities that will arrive with smart appliances, connected homes and electric vehicles. DPV may be particularly attractive for rural customers located far from existing distribution infrastructure.

It is well established that the Companies have the responsibility to provide least-cost solutions, which would be DPV paired with storage/flex loads in some jurisdictions. The

[64] Ryan Hledik et al., *Assessing VPP Performance: Impacts of a Test Event in California*, Brattle Group, at 1 (Aug. 1, 2025), https://www.brattle.com/wp-content/uploads/2025/08/Assessing-VPP-Performance-Impacts-of-a-Test-Event-in-California-1.pdf.

Companies should be pursuing the High distributed generation ("DG") growth scenario in the IRP, which shows over 800 MW capacity by 2030.[65] The Companies should be planning to achieve high growth, not devaluing PV and thus undermining growth potential.

Researchers agree that DPV, combined with DER, can provide increasing value in terms of avoided costs.

> Indeed, with increasing levels of DER adoption, authors acknowledge that some value categories will shift upward in magnitude and will have a large impact on overall value, necessitating inclusion in the value stack. As time progresses, value categories will likely shift in magnitude (upward or downward) and increase in feasibility as DER penetration increases and as regions enhance quantification methods, models, data collection, and evaluation techniques.[66]

Once DPV and other DER are in place, third-parties or the Companies can plan to aggregate those resources into virtual power plants. One example of a potential third party in Kentucky is Virtual Peaker.

### *C. Bill Credit Calculation*

**Q: Do the Companies follow Commission direction calculating netting payments for NMS-2 bill credit customers?**

A: No.

**Q: What are the Companies doing that conflicts with Commission guidance?**

A: For NMS-2 customers, the Companies are calculating bill credits using "instantaneous netting" of all solar exports, rather than using monthly netting, as required by statute and previous Commission orders. This practice lowers the potential compensation for NMS-2 customers because it leaves other (monthly) bill charges out of the netting equation,

[65] Schram Direct, Ex. CRS-6 at 6. See Plexos results with 815 MW solar in high gas price scenarios.
[66] Sydney P. Forrester and Eric O'Shaughnessy, *A review of value of solar studies in theory and in practice*, Nat'l Renewable Energy Lab'y, at 14 (Jan. 2025), https://eta-publications.lbl.gov/sites/default/files/2025-01/20250123_final_vos.pdf.

including fuel charges. Furthermore, when the export rate is lower than the retail rate, instantaneous netting devalues all solar exports, rather than just the net exports at the end of the billing period. This can significantly reduce the value of solar generation for customer-generators.

In its "Order on Rehearing" in the Companies' last base rate case (2020-00350), the Commission ordered that "LG&E/KU should **continue** to net the dollar value of the total energy consumed and the dollar value of the total energy exported by eligible customer generators over the billing period in NMS 2 **consistent with the billing period netting period established in NMS 1**."[67]

I therefore recommend that the Commission order the Companies to use monthly netting of solar generation in the calculation of bill credits.

**Q: Are the Companies required to stop enrolling DPV owner-generators in NMS-2 after the 1% of peak load threshold is reached?**

A: No. The Companies have the option of continuing to offer the tariff rather than treating DPV owner-generators as QFs.

**Q: What are ratepayers and DPV owner-generators risking if the Companies stop offering NMS-2?**

A: The Companies' proposal to stop offering NMS-2 beyond the 1% threshold unreasonably and unnecessarily truncates the potential for the program to deliver benefits for both participants and non-participants. As described earlier in this testimony, the benefits of DPV increase with increased scale.

[67] Case No. 2020-00349, Order at 25 (Nov. 4, 2021) (emphasis added).

As deployment of DPV grows, DPV can be paired with smart inverters, two-way AMI (already in place) and price signals (TOU rates, DR programs) to maximize their aggregate potential value for the grid while minimizing risks, thereby eliminating the need for the 1% cap.

Further, there is ample evidence from many utility companies where rooftop solar penetration is well beyond 1%. For example, California and Arizona utilities manage systems with penetrations well beyond 15% with no operational consequences.[68] Hawaii is nearing 50% penetration.[69] Australia similarly has reached half of its customers.[70] In the Southeast, North Carolina reached 8% generation from solar as of 2022.

Figure JF-5 from NREL shows the very high levels of penetration of solar generation by state, and that NEM rules were revised well above the 1% level.[71] Program caps have increased over time.[72] Figure JF-6 shows that many states have net metering caps well above 1%.

[68] For California, *see* California Distributed Generation Statistics (current as of May 31, 2025), https://www.californiadgstats.ca.gov/charts/ and CAISO, *California ISO Peak Load History 1998 through 2023*, https://www.caiso.com/Documents/CaliforniaISOPeakLoadHistory.pdf (last visited Aug. 29, 2025). For Arizona, *see* APS-24, Direct Testimony of Jamie R. Moe, Docket No. E-01345A-22-0144 (Ariz. Corp. Comm'n Oct. 28, 2022).
[69] In Oahu, 42% of residences have DPV. Hawaiian Electric, *Hawaiian Electric sees steady growth in solar installations: New systems added in 2024 bring five-island total to nearly 114,000* (Mar. 18, 2025), https://www.hawaiianelectric.com/hawaiian-electric-sees-steady-growth-in-solar-installations.
[70] For Australia, *see* Ev Foley, *Worth its weight in sunshine, rooftop solar clocks new supply records*, PV Magazine (Nov. 13, 2024), https://www.pv-magazine-australia.com/2024/11/13/worth-its-weight-in-sunshine-rooftop-solar-clocks-new-supply-records/.
[71] Eric O'Shaunessy et al., *Rooftop Solar Deployment, Potential Electricity Rate Impacts, and the Timing of Revisions to State Net Metering Policy*, Nat'l Renewable Energy Lab'y, at 3 (Jan. 2025), https://docs.nrel.gov/docs/fy25osti/91888.pdf.
[72] J. Heeter et al., *Status of Net Metering: Assessing the Potential to Reach Program Caps*, Nat'l Renewable Energy Lab'y, at 8-11 (Sept. 2014), https://docs.nrel.gov/docs/fy14osti/61858.pdf.

***Figure JF-5: Solar Generation as Percentage of Total Generation by Year and State, and Penetration Level when NEM Revisions Were Implemented***

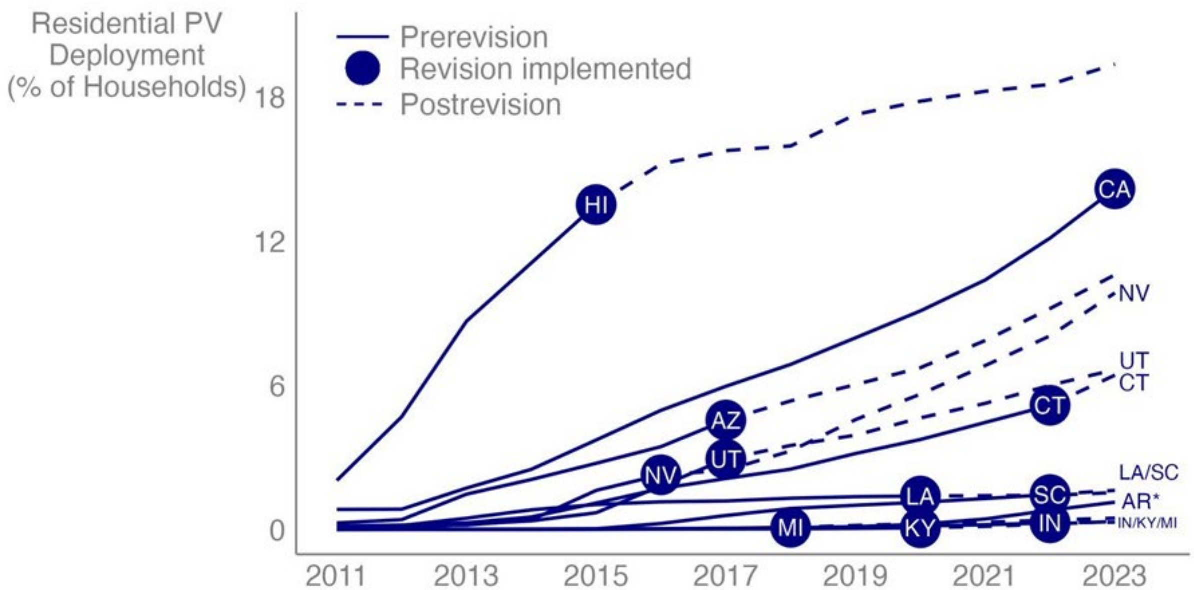
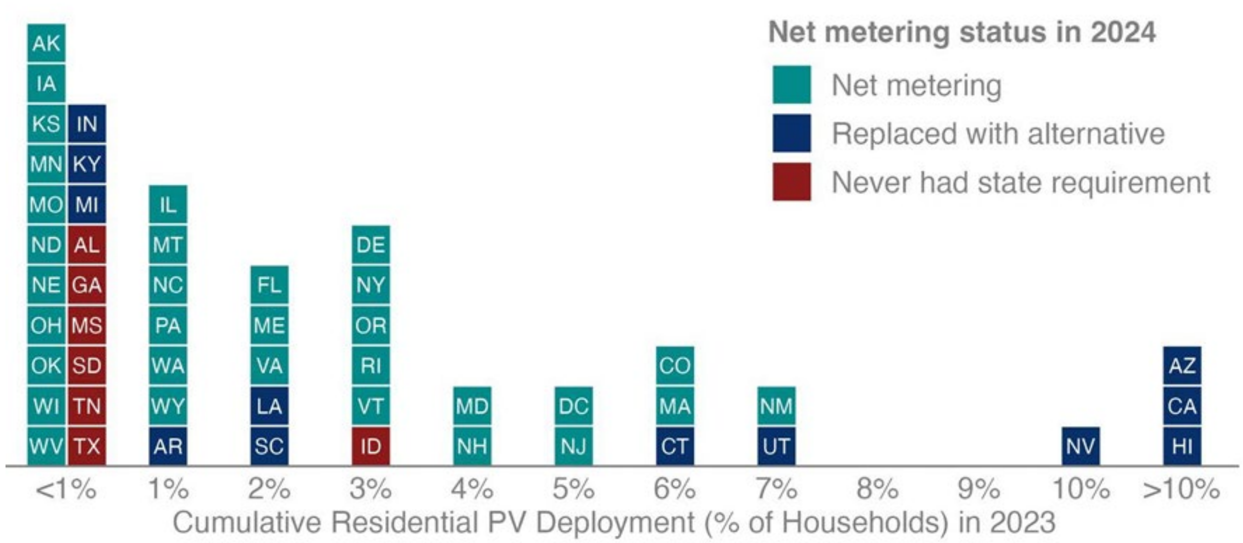



***Figure JF-6: Number of States with NEM Caps by Cap Percentage***




Even well above 1%, rate impacts for non-rooftop solar customers are likely to be very small. Researchers at Lawrence Berkeley National Labs found:

- in all 30 states with a PV deployment rate below 3% of households, net metering is unlikely to be associated with an increase in rates of more than $1 per month per customer without PV.
- Among states with a PV deployment rate between 3% and 7% of households, potential rate impacts are less than $1/month/customer in two-thirds of the states and $2-$6/month/customer in one-third of the states. [73]

Even so, a detailed study done by M.Cubed in California shows that the non-participant rate impacts are actually negligible and even beneficial.[74]

The Companies' intention to stop offering NMS after reaching 1% is overly conservative and will result in unnecessary customer costs because increasing NMS penetration will continue to yield net benefits for all ratepayers.

## IV. <u>TARIFF EHLF</u>

**Q: Please summarize the Companies' proposed Tariff EHLF.**

A: The Companies have proposed a new tariff for large loads with high load factors as a means to recover the grid expansion costs anticipated to be needed to support economic development. Of principle interest for this tariff are data centers that promise massive new demand. In anticipation of the need to serve that demand, the Companies are proposing new

[73] Eric O'Shaunessy et al., *Rooftop Solar Deployment, Potential Electricity Rate Impacts, and the Timing of Revisions to State Net Metering Policy*, Nat'l Renewable Energy Lab'y, at iv (Jan. 2025), https://docs.nrel.gov/docs/fy25osti/91888.pdf.

[74] Cal. Solar & Storage Ass'n and M.Cubed, *Rooftop Solar Reduces Costs for All Ratepayers*, 8-20 (Feb. 2025), https://mcubedecon.com/wp-content/uploads/2025/02/calssa_rooftop-solar-reduces-costs-for-all-ratepayers-2025.pdf.

generation, transmission and distribution infrastructure. Tariff eligibility is tied to energy demand (at least 100 MVA, or 100 MW) and a load factor (at least 85%).[75]

The Companies have proposed several tariff terms to reduce the risk that other ratepayers will need to cover costs should the new data centers close prior to the end of the minimum 15-year contract. Importantly, the Companies propose an exit fee, to be calculated as the nominal value of the remaining minimum non-fuel revenue over the remaining contract term.

**Q: How might the Commission balance risk and reward for ratepayers and investors when the grid is being expanded to meet the needs of a small subset of high-load customers?**

A: When the Commission approves utility investments, there is always a balance of risk and reward. The reward is reliable electricity service for all customers, including newcomers, whereas the risk is overinvestment in capacity that is neither used nor useful. To dissuade utilities from overinvesting in cases where risks are borne by rate payers, returns are specified and capped, and proposals are vetted publicly prior to approval by the Commission.

In the case of investments to support anticipated new load from data centers and manufacturing facilities, the Companies have proposed implicitly to share investment risks with ratepayers by asking them to be the backup funding source that covers unrecovered costs such as stranded asset investments if the data centers are not built as promised, while retaining the full opportunity for rewards. This is an unfair arrangement. Instead, rate payers sharing risks of overinvestment should also be in line for rewards. Alternatively, should rate payers not be positioned to enjoy rewards, then they should not be exposed to related risks.

[75] Direct Testimony of Michael E. Hornung, Manager, Pricing/Tariffs on Behalf of Kentucky Utilities Company and Louisville Gas and Electric Company, Case Nos. 2025-00113 and 2025-00114, at 4 (May 30, 2025) ("Hornung Direct").

The Companies recognize the concerns related to over-investment in support of electricity demand that never manifests or does so at substantially lower levels than expected, or that does not have anticipated attributes, notably high load factors. To mitigate this concern, my testimony makes several recommendations.

**Q: What are your recommendations for the EHLF rate?**

A: The Companies are planning to expand grid assets to meet a small number of high-load customers. Absent new electricity demand from anticipated data centers and a few dozen manufacturing developments, the Companies agree that the recent trend of declining coincident peak demand will continue. Therefore, it is reasonable and fair for the customers creating those new loads, rather than ratepayers writ large, to bear the full cost of recovering grid expansion investments.

The Commission should require a main meter on major development that is the point of measurement for the Rate EHLF, thereby avoiding aggregation concerns. In addition, or in the alternative, the Commission should also set an MVA threshold of no greater than 50 MVA.

The Commission should eliminate the load factor tariff eligibility threshold, because data centers do not necessarily maintain the high load factors and they may have flexible loads in at least some circumstances.[76] Rather than implementing a load factor tariff eligibility

[76] *See* Tyler Norris et al, *Rethinking Load Growth* (Feb. 2025), https://nicholasinstitute.duke.edu/publications/rethinking-load-growth; *see also* Tyler Norris, *The Puzzle of Low Data Center Utilization* (Aug. 7, 2025), https://www.powerpolicy.net/p/the-puzzle-of-low-data-center-utilization. For instance, Google recently entered into two demand response agreements with Indiana Michigan Power and Tennessee Valley Authority, which will allow it to reduce power use during times of high grid stress. These agreements are currently under review. Verified Petition, *In re Petition of Indiana Michigan Power Company for Approval of: (1) a Customer-Specific Clean Capacity Arrangement and Demand Response Contract; and (2) Associated Cost Recovery; and (3) to the Extent Necessary, an Alternative Regulatory Plan*, Cause No. 46276, (Ind. Util. Regul. Comm'n July 30, 2025); *see also* Bianca Giacobone, *Google expands demand response to target machine learning workloads*,

threshold, the Companies should require minimum load flexibility requirements and take steps necessary, such as marketing, education, outreach and new program creation, to facilitate EHLF customers delivering on their flexibility commitments.

The Commission should not allow data centers and other large loads to skirt their responsibilities. The principle of cost causation means that those who cause the cost ought to pay for it. In this case, the new large loads should pay for their full cost of service and take on all risks of stranded assets. As such, the Commission should open a docket as soon as possible to assess and implement alternate cost allocation structures in order to ensure that residential and other customer classes are not unfairly burdened with the substantial production, transmission, and distribution costs that are projected to be incurred to serve Rate EHLF customers.

The project ramp-up period should be separated from the 15-year minimum contract term for Rate EHLF.

The exit fee requirement should be approved, and the collateral requirement should be strengthened to more fully protect other ratepayers.

The security requirements like exit fees and security deposits may become an incentive to define capacity additions as outside the EHLF tariff requirements. Here again, the Commission should review proposed investments to determine the extent to which they are caused by EHLF rate-eligible customers.

**Q: What is the Companies' proposal for EHLF tariff eligibility?**

A: Customers with demands over 100 MVA and load factors averaging above 85% are eligible.

---

Latitude Media (Aug. 4, 2025), https://www.latitudemedia.com/news/google-expands-demand-response-to-target-machine-learning-workloads/.

**Q: Are those eligibility requirements reasonable and fair?**

A: No.

The Companies recognize appropriately that "one or just a few such customers could require the Companies to acquire additional generation resources to supply their needs and the needs of existing customers, increased minimum billing demands, extended contract terms, and enhanced collateral requirements are appropriate for such customers."[77]

The Commission should eliminate unnecessary pathways for data centers to avoid paying their fair share, such as load factor eligibility threshold and an unreasonably high MVA floor, to help ensure that the EHLF tariff adequately protect ratepayers from bearing costs caused by one or a few large customers. As proposed, the EHLF's eligibility provisions allow sub-100 MVA or marginally lower-load factor loads to avoid paying their fair share even though those loads are associated with the large new customers.

Notably, the Companies included high load factor loads above 50 MVA in the non-unanimous settlement proposed in the CPCN proceeding, a compromise that will include more loads.[78] Regardless of whether that settlement is approved, that lower threshold for Rate EHLF should be included in the design to avoid the risk of excluding new data centers that are in LGE-KU's economic development queue.[79]

Another approach is to require large new commercial developments to use a master meter that is the measurement point for EHLF rate eligibility. The landowner would then be

[77] Hornung Direct at 4.
[78] Case No. 2025-00045, Stipulation Testimony, Ex. 1 at 7 (July 29, 2025), (defining "eligible data center" for purposes of EHLF-related cost recovery agreements as any facility with expected or actual peak of real-time energy demand between 50 and 100 MVA; and expected or actual monthly load factor greater than or equal to 75%).
[79] *See* Case Nos. 2025-00113 and 2025-00114, Companies' Resp. to JI 2-3 (stating that the Company expects to enter into an Electric Service Agreement with each metered customer, rather than the owner or developer of a multi-tenant data center facility); Companies' Resp. to JI 2-4 (same).

responsible for the EHLF rate, not the individual tenants, thereby avoiding situations where a large individual data center site tries to avoid coverage under EHLF based on multiple tenants being just below the MVA cutoff.

The Commission should also eliminate the load factor tariff eligibility threshold, because data centers do not necessarily maintain the high load factors that are portrayed in the media.

**Q: What do real data center operations indicate about load factors?**

A: There are several reasons why load factors may be lower than expected, including

- Maintenance and redundancy results in equipment downtime.
- Oversizing results from data centers routinely requesting and designing capacity well above expected near term use to avoid constraints in the future.
- Nameplate usage is often well above actual usage.
- Workload demands may be inconsistent and highly variable.
- Hardware may be fragile at scale, limiting GPU usage.[80]

The 2024 U.S. Data Center Energy Usage Report described a trend of increasing data center load factors in terms of server utilization. [81]

> Following trends in the 2016 report, utilization for conventional servers in all space types increases slightly through 2028. Servers in internal and small data centers average 11% utilization in 2014, rising linearly to 20% in 2027. Colocation data centers average 21% utilization in 2014, rising to 35% in 2027. Hyperscale data centers average 45% in 2014, rising to 50% in 2027.[82]

Of even greater concern, load factor requirements create an incentive for data centers to use power during the coincident system peak when they should be doing the opposite: using flexibility to avoid putting pressure in system resources at times of stress.

[80] Norris, *The Puzzle of Low Data Center Utilization*, *supra* note 77.
[81] Arman Shehabi et al., *2024 United States Data Center Energy Usage Report*, Lawrence Berkeley Nat'l Lab'y, at 27 (Dec. 2024).
[82] *Id.*

**Q: Have the Companies justified the 100 MVA threshold?**

A: No. The Companies have stated that:

> The 100 MVA load size was chosen based on the combination of understanding Companies' resource needs to serve large loads and peer industry review. Loads lower than 100 MVA do not require the same level of investment to serve and would fall under the traditional Retail Transmission Service.[83]

However, the Companies have refused to provide any analysis supporting their assertion that the 100 MVA threshold is appropriate on the basis of investment needs.[84] Furthermore, the Companies' justification for a 100 MVA load size threshold does not hold up in light of the structure of co-located data center campuses. The Companies may need to plan investments for data center campuses that collectively have the resource needs equivalent to a greater-than-100-MVA customer. However, if each individual end-use data center falls below 100 MVA, none of the end-use customers would be eligible for Rate EHLF.[85] In such an instance, other ratepayers would be left facing greater risk of the investments made to serve the co-location data center campus.

Notably, in a proposed stipulation that the Companies have signed in Case No. 2025-00045, the Companies have proposed a cost recovery mechanism for Mill Creek 6, which is a combined cycle gas turbine that the Companies claim is proposed primarily to serve forecasted data center load growth. For purposes of cost recovery, that stipulation would

[83] Case No. 2025-00113, KU Resp. to Staff 3-70(c).
[84] *See* Response of Kentucky Utilities Company to Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association's Initial Request for Information Dated July 3, 2025, Case No. 2025-00113, Question 162 (July 16, 2025); Response of Kentucky Utilities Company to Sierra Club Initial Request for Information Dated July 3, 2025, Case No. 2025-00113, Question 6 (July 16, 2025) ("KU Resp. to SC 1-6").
[85] *See* Response of Kentucky Utilities Company to Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association's Supplemental Request for Information Dated July 31, 2025, Case No. 2025-00113, Questions 3, 4 (Aug. 12, 2025); Case No. 2025-00045, Aug. 7, 2025 HVT at 2:08:25 to 2:12:44 P.M.; Aug. 6, 2025 HVT at 9:40:22 to 9:41:35 A.M.

include data centers with peak demand between 50 MVA and 100 MVA as "eligible data centers."[86] In explaining the inclusion of data centers between 50 MVA and 100 MVA, LG&E-KU witness Bellar explained that the Companies "wanted to have in the stipulation a recognition that customers could fall below that threshold of 100 [MVA] and wanted to capture those revenues . . . between 50 MVA and 100 MVA," calling into question the notion that loads lower than 100 MVA do not require the same level of investment to serve.[87]

Furthermore, East Kentucky Power Company's ("EKPC") proposed Rate DCP (Data Center Power) would use a *significantly* lower 15 MW threshold.[88] The Companies claim that they are "aware of and have reviewed, but have not prepared a written evaluation of, East Kentucky Power Cooperative's Rate DCP (Data Center Power),"[89] yet the Companies have not made any effort to explain why their proposed eligibility threshold is so much higher than EKPC's.

Reviewing confidential information about economic development projects in the queue indicates the number of facilities and their peak loads, and shows that a [redacted]

---

[86] Case No. 2025-00045, Stipulation Testimony, Ex. 1 at 3.
[87] Case No. 2025-00045, Aug. 4, 2025 HVT at 2:31:46 to 2:32:33 P.M.
[88] Electronic Tariff Filing of East Kentucky Power Coop., Inc. to Establish a New Tariff for Data Center Customers, Case No. 2025-00140 (Apr. 30, 2025), at Original Sheet No. 103.
[89] Case No. 2025-00113, KU Resp. to SC 1-6.

[redacted]

In light of the Companies' failure to justify a 100 MVA threshold, I recommend a threshold of no greater than 50 MVA.

**Q: Is there a need to compel multiple data center loads to be aggregated as a single entity?**

A: Yes.

The Commission should not allow data centers and other large loads to skirt their responsibilities. The principle of cost causation means that those who cause the cost ought to pay for it. In this case, the new large loads should pay for their full cost of service and take on all risks of stranded assets.

The Companies claim that Commission regulation 807 KAR 5:041 Sec. 9(2) prohibits load aggregation when determining Rate EHLF eligibility.[91] They also state that "nothing that would preclude the Companies from seeking to require a customer who so clearly sought solely to evade the EHLF tariff provisions to enter into special contracts that included all the same rates, terms, and conditions as Rate EHLF (except the greater-than-100 MVA eligibility requirement)."[92]

**Q: What is a way to avoid aggregation concerns?**

---

[90] Case No. 2025-00113 and 2025-00114, Companies' Resp. to Staff 2-32, Confidential Attachment ("Project Tracking").
[91] *See* Case No. 2025-00113 and 2025-00114, Companies' Resp. to JI 2-26; Response of [Companies] to Sierra Club's Supplemental Request for Information Dated July 31, 2025, Questions 3(a) (Aug. 12, 2025) ("Companies' Resp. to SC 2-3(a)").
[92] Case No. 2025-00113 and 2025-00114, Companies' Resp. to SC 2-3(a).

A: Assuming that the Companies' legal interpretation of 807 KAR 5:041 Sec. 9(2) is accurate, one solution is to require a main meter at each major development that is subject to the EHLF tariff. The main meter owner will be free to negotiate tariff terms with tenants, and it will obviate concerns about the need for aggregation.

**Q: Does Rate EHLF as proposed by the Companies protect all ratepayers from financial risks of investment to serve EHLF customers?**

A: No.

**Q: Why are ratepayers exposed to risks under the Rate EHLF proposal?**

A: There are several reasons why ratepayers face risks. For one, the Companies' currently coincident peak method for cost allocation will very likely shift significant costs for serving data center demand to residential and other customer classes.

Furthermore, there is still potential for stranded assets, despite the Companies proposed terms. One reason for this is the fact that the minimum contract term of 15 years is proposed to be inclusive of the ramp-up period, and the ramp-up period is proposed to be determined on a case-by-case basis and without limitation.[93] The inclusion of an uncapped ramp-up period in the minimum contract term is essentially an escape clause to end payments before costs are recovered fully, because customers would not have any mandatory timeframe in which to reach the demand levels established in the contract.

The Companies have not met their burden to prove that a 15-year contract term with an included, uncapped ramp-up period will allow for sufficient cost recovery from EHLF customers.[94] Notably, the Commission approved a 20-year minimum contract term in

[93] *See* Case No. 2025-00113 and 2025-00114, Companies' Resp. to JI 2-10.
[94] *See* Case No. 2025-00113, KU Resp. to JI 1-159(b), Case No. 2025-00114, LG&E Resp. to JI 1-168(b) (refusing to provide any workpapers, analyses, studies, or other supporting documents supporting the proposed minimum contract length).

Kentucky Power Company's General Service Tariff large load tariff provisions.[95] Furthermore, many other utilities have proposed or adopted large load tariffs that cap the ramp-up period and separate it from the minimum contract term.[96] I recommend that the ramp up period should be either limited to a few years, or exclusive of the project contract term commitment.

**Q: Does the Companies' Rate EHLF proposal follow cost causation principles?**

A: No.

**Q: Why not?**

A: The Companies' proposal fails to fully follow cost causation. Minimum billing demand is currently proposed at 80% of maximum contract capacity. This means new load is committed to being billed for costs that the utility incurs to serve them, but the utility must build capacity to serve 100% of anticipated demand (and more, for contingencies, reserves

---

[95] Order, *In re Kentucky Power Company to Revise its Industrial General Service Tariff*, Case No. 2024-00305, at 3 (Mar. 18, 2025).

[96] Revised Tariff Sheets, *In re Appalachian Power Company and Wheeling Power Company Application for Approval of Revisions to Schedules LCP and IP*, Case No. 24-0611-E-T-PW, (W.V. Pub. Serv. Comm'n Apr. 7, 2025), First Revision of Original Sheet No. 14-3, https://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=639454&NotType=WebDocket; Submission of Industrial Power Tariff – Tariff I.P., *In re Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff I.P.*, Cause No. 46097 (Ind. Util. Regul. Comm'n Feb. 25, 2025), First Revised Sheet No. 21.3, https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/ba79885d-47f4-ef11-be20-001dd80ad83d/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=46097_IndMich_Tariff%20Submission_022525.pdf; , Joint Motion for Approval of Unanimous Settlement Agreement and Amendment of the Procedural Schedule, *In re Application of Evergy Kansas Metro, Inc., Evergy Kansas South, Inc., Evergy Kansas Central, Inc. for Approval of Large Load Power Service Rate Plan and Associated Tariffs*, Case No. 25-EKME-315-TAR (Kan. State Corp. Comm'n Aug. 18, 2025), Attach. 1 at 4, https://estar.kcc.ks.gov/estar/ViewFile.aspx/S202508181202168915.pdf?Id=9e907841-85a6-49d2-8321-59acf777cfd618, 2025), https://estar.kcc.ks.gov/estar/ViewFile.aspx/S202508181202168915.pdf?Id=9e907841-85a6-49d2-8321-59acf777cfd6; Application, *In re Application of Consumers Energy Company for Ex Parte Approval of Certain Amendments to Rate GPD*, Case No. U-21859, at 3-4 (Mich. Pub. Serv. Comm'n Feb. 7, 2025), https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000ZUNZTAA5.

margin and line losses). The proposed approach could mean burdening rate payers to cover a significant and unfair portion of capacity costs. One way to avoid this risk for ratepayers is to ensure the EHLF rate is designed to recover all costs within the signed contract period and to increase the minimum billing requirement above 80%, while still providing incentives to avoid load during peak times. The load flexibility will enable the Companies to plan for reliable service without having to add the entire new load to peak hour reliability assessments that can lead to requirements for more resource procurement.

**Q: Is there a solution to avoid stranded assets and costs to be recovered from ratepayers?**

A: Yes. An exit fee set at a level that ensures other rate payers are not left with the costs of stranded assets will work if oversight is strong to ensure (a) exit fees are calculated at the outset of the project and (b) that sufficient financial guarantees are in place also at project initiation, such as security bonds and insurance. In this respect, I support the currently proposed definition of an exit fee as "the nominal value of the remaining minimum non-fuel revenue over the remaining term." However, the Companies' proposed collateral term could be strengthened. The Companies have proposed a collateral requirement equal to 24 months of the minimum billed amounts at the largest contract capacity value,[97] but the Companies have not demonstrated that this collateral amount is sufficient to protect against the risk of EHLF customer default.[98] In contrast, a recent AEP Ohio approved settlement set the collateral at 50% of the customer's total minimum charges for the full term of the contract, a more protective approach to collateral than proposed by the Companies.[99] I recommend the

[97] Hornung Direct at 6:15-18.
[98] *See* Case No. 2025-00113, KU Resp. to JI 1-159(e); Case No. 2025-00114, LG&E Resp. to JI 1-168(e) (refusing to provide any workpapers, analyses, studies, or other supporting documents supporting the proposed collateral requirement).
[99] *See* Joint Stip. and Recommendation, *In the Matter of* the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers, Case No. 24-508-EL-ATA, Ex. A at 5-6

Commission adopt the strongest possible provisions for collateral and risk reduction on behalf of all ratepayers, including a collateral requirement at least as protective as AEP Ohio's.

Furthermore, if tenants are exiting contracts due to bankruptcy, remaining energy bills and exit fees should be top priority for repayment. To ensure this, the utility would be made the senior creditor, and all other creditors would be subservient. The rationale is that other debts may be private liens, whereas the exit fee (and other unpaid electricity bills) are debts owed to ratepayers (i.e., society).

The security requirements like exit fees and security deposits may become an incentive to define capacity additions as outside the EHLF tariff requirements. Here again, the Commission should review proposed additions to determine the extent to which they are caused by EHLF rate-eligible customers.

**Q: Are there other approaches the Companies can use to reduce the chance the ratepayers bear a cost burden for capacity investments to serve Rate EHLF customers?**

A: Yes. The new loads can be expected to be connected, responsive to signals and prices, and flexible, rather than 99.999% running at peak demand. There is a misperception between data center availability for customers, and the notion that data centers servers are being utilized at full tilt all the time.

In fact, these new loads are flexible and may not contribute to system coincident peak that is the organizing metric for allocating costs associated with new capacity

---

(Ohio Pub. Utils. Comm'n Oct. 23, 2024), https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A24J23B55758I01206; Order and Opinion, *In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers*, Case No. 24-508-EL-ATA, at 16 (Ohio Pub. Utils. Comm'n July 9, 2025), https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A25G09B43531I00509.

investments. Whether and to what extent new loads contribute to coincident system (or subsystem) peaks is less important to debate and more important to manage with demand-side solutions. I recommend the Companies require minimum load flexibility requirements and take steps necessary, such as marketing, education, outreach and new program creation, to facilitate EHLF customers making and delivering on flexibility commitments.

**Q: Should the Commission establish a new proceeding to determine appropriate cost causation for high load customers?**

A: Yes. The amount and type of loads presented by potential data center customers is unprecedented, and raises a very high likelihood that current cost allocation methodologies that prioritize coincident peak demand would not be protective of other customer classes. There are, however, a number of other approaches to cost allocation that could help minimize the extent to which the production, transmission, and distribution costs of serving data center load are not unfairly shifted to residential and other customer classes that do not cause those costs.

I appreciate that the current docket does not provide sufficient evidence for the Commission to take up these cost allocation issues in this docket. The Commission should open a docket as soon as possible to assess and implement the alternate cost allocation structures described in this testimony, in order to ensure that the Companies' cost allocation structure does not unfairly burden other ratepayers with costs that should be paid by Rate EHLF customers.

When scoping a new proceeding, I recommend that the Commission consider the following:

- The production, transmission, and distribution costs to serve EHLF customers will inevitably be quite high. For instance, in Case No. 2025-00045, the Companies have requested Commission approval for projects with a projected combined capital cost of \$3.725 billion, including two combined cycle gas plants with projected capital costs of \$1.383 billion and \$1.415 billion.[100]
- Under cost causation principles, those costs should be borne primarily by the EHLF customers.
- The Companies have not undertaken any analysis of the cost allocation or rate and bill impacts of adding significant EHLF load to its system.[101]
- The current cost allocation methodology would almost certainly shift substantial costs to residential and other customer classes.

A dedicated proceeding would allow for consideration of potential alternative cost allocation methods. Potential options that could be considered include: (1) marginal cost ratemaking, (2) shifting allocation more towards energy rather than demand, (3) probability of dispatch, (4) direct assignment of certain costs that are primarily attributable to one or more EHLF customers, and (5) basing any coincident peak allocation on 12CP rather than 6CP. There may, of course, be other methodologies worth considering in that proceeding.

The Commission should open a special docket within 6 months to fully evaluate what cost allocation method(s) are most appropriate for the generation, transmission, and distribution costs that will be incurred to serve EHLF customers.

**Q: Does this conclude your testimony**

A: Yes.

[100] Case No. 2025-00045, Joint Application at 12 (Feb. 28, 2025).
[101] *See* Case No. 2025-00113, KU Resp. to JI 1-170; Case No. 2025-00114, LG&E Resp. to JI 1-179.

# EXHIBIT JF-1

**JAMES DAVID FINE, PH.D.**

**EXECUTIVE BIOGRAPHY**

# Executive Biography for James David Fine, Ph.D.

James "Jamie" Fine is an expert in clean energy, climate and transportation policy with over two decades experience in several US states, including California, Texas, New York, Illinois, North Carolina and Florida. Jamie provides expert analysis and testimony in support of clean electricity generation, demand response and other distributed energy resources, electricity rate designs, climate actions, and transportation decarbonization initiatives.

Jamie provides technical assistance to stakeholders, including environmental justice communities, demand response providers, electric utilities and public agencies. He is trusted by lawmakers and regulators to provide well-informed advice in the public interest. Jamie's actions led to the adoption of California's climate, vehicles and energy policy regime, including time-of-use pricing plans, demand response programs, advanced clean trucks and greenhouse gas cap-and-trade.

Jamie's primary products are transparent, actionable, quantitative models, research reports, testimony and direct engagement with stakeholders. His models allow for uncertainty and scenario analyses and forecasting economic and environmental impacts of policies and practices. Recently, he developed modeling tools to:

- Calculated electric truck payback periods in comparison to conventional options under a variety of scenarios.
- Estimated emissions, fleet transition and equity impact of policies for clean vehicles, such as tax credits and grants,
- Quantified economic and environmental benefits to consumers associated with decarbonizing trucks and buses.
- Expanded the comparison of ICE v electric trucks to include a full set of costs and benefits.

Dr. Fine grounds his work via collaboration. He works with environmental justice advocates, investor-owned and municipal utilities, researchers in academia, regulators and business leaders. He is a Board Member of the West Oakland Environmental Indicators Project. During the Obama Administration, Jamie was a member of the National Institute of Standards and Technology Smart Grid Advisory Board. He served on the Bay Area Air Quality Management District's Cumulative Air Risk Evaluation task force.

His research initiatives include studying the energy performance of homes in Huron, California, in partnership with the Mayor and Cornell University, electricity users adopting time-of-use pricing, forecasting benefits of replacing public fleets with clean vehicles, and financial payback periods for electric trucks under a variety of energy price and policy scenarios.

Skills

- Policy Impact Analysis
- Government Affairs
- Expert Testimony
- Economic and Environmental Impact modeling
- Forecasting
- Uncertainty Analysis
- Stakeholder engagement
- Scholar collaboration

Areas of Expertise

- Climate policy & action plans
- Energy policy
- Integrated resource procurement and transmission plans
- Residential & vehicle electricity pricing plans
- Demand response & other distributed energy resources
- Heavy-duty vehicles economics

**James David Fine, Ph.D.**
jamiedfine@gmail.com 415-516-1503

## EDUCATION

Energy and Resources Group, University of California, Berkeley, CA

- Ph. D. in Energy and Resources, May 2003
  Dissertation: *The Ends of Uncertainty: Air Quality Science and Planning in California's Central Valley*
- M. S. in Energy and Resources, May 1998
  Thesis: *Using Tradable Particulate Emissions Permits to Improve Air Quality in California's Central Valley*

Wharton School of Business, University of Pennsylvania, Philadelphia, PA

- B. S. in Economics, May 1989

## PROFESSIONAL EXPERIENCE

LEAD SENIOR ECONOMIST, Environmental Defense Fund **2007 - 2024**

- Led research and analysis to support heavy-duty vehicle advocacy that led to adoption of advanced clean truck rule goals in over a dozen U.S. states.
- Provided expert testimony for public agency proceedings on climate policy, residential and electric vehicle tariffs, grid modernization, storage and clean energy mandates, distribution system planning, integrated resource planning, and demand response programs.
- Respected voice in designing California's climate cap and trade and advance vehicles programs.
- Developed policy analyses to evaluate the potential impacts, including emissions and economic dimensions of transitioning to all-electric trucks.
- Hosted research fellows and interns who completed research projects to support advocacy goals.
- Supervised analysts and collaborated with experts to support regulatory and policy initiatives, stakeholder engagement, fundraising and communications campaigns.

SENIOR VISITING ADVISOR, OhmConnect, Inc. **Jan 2019 – July 2019**

- Evaluated successes and gaps in disadvantaged communities associated with creating virtual power plants.
- Developed, pitched and won a proposal for funding in support of a multi-year, multi-million dollar jobs initiative.

COMMITTEE MEMBER, Smart Grid Advisory Committee **Aug 2017 - Aug 2019**
National Institute of Standards & Technology

INDEPENDENT CONTRACTOR, ENVAIR & M.Cubed **1994 - 2007**

<u>Energy Economics Modeling</u>

- Compared costs of decommissioning or relicensing the Klamath Dam complex.
- Forecasted energy demand and production/delivery capacity for the City of San Francisco.

<u>Air Quality and Transportation</u>

- Analyzed the costs incurred by the construction industry to comply with the off-road diesel vehicle emissions reduction rule proposed by the California Air Resources Board.
- Calculated public revenues and expenditures associated with surface transportation (state highways, local roadways, mass transit service) in the six counties encompassing Chicago.
- Wrote a technical report about nitrogen oxides pollution that surveys existing legislation and regulation, analyzes issues that may lead to further emissions controls, lists emissions sources, and identifies future research needs
- Conducted research for an economic impact analysis of the California Air Resources Board's State Implementation Plan for attainment of national ambient air quality standards

<u>Water Quality and Water Rights Economics</u>

- Evaluated the potential for implementing a tradable discharge permit program to reduce nonpoint sources of water pollution in the Oregon's Deschutes River Basin
- Estimated the fair market value of a farmer's water right to facilitate its acquisition by federal agents to augment river flows for fish habitat

## PROFESSIONAL EXPERIENCE (Continued)

### ASSISTANT & ADJUNCT PROFESSOR, Univ. of SF, Dept Env. Science & Studies **2003-2007**

- Teach graduate courses in the Masters of Science in Environmental Management program
- Teach undergraduate courses in the Environmental Science and Environmental Studies majors
- Oversee and advise graduate students' research

### BOARD MEMBER, West Oakland Environmental Indicators Project **2005-Present**

- Coordinating Team Member and Board Member
- Co-Chairing (with EPA) of West Oakland Toxics Reduction Collaborative Alternative Fuels Team
- Cal-EPA grantee to serve as Technical Advisor to West Oakland community in goods movement planning

### MEMBER, Cumulative Air Risk Evaluation Community Task Force, **2005- 2012**

- Member of Task Force convened by the Bay Area Air Quality Management District
- Conducting community-based participatory research on diesel particulate emissions in West Oakland to inform the second phase of the BAAQMD's toxic air contaminate emissions estimates. USF students are conducting research on questions posed by community members about the CARE study. Research topics include truck driver socioeconomic survey, truck traffic activity observations, and forecasting construction-related emissions.

### RESEARCHER, Lawrence Berkeley National Lab, Atmospheric Sciences Program **1999-2003**

<u>Ozone Air Quality Modeling and Planning</u>

- As part of dissertation research, reviewed methods to estimate photochemical air quality simulation model uncertainties and evaluated the potential utility of uncertainty information for use in policy-making.
- Interviewed agency planners, modeling technicians, and stakeholder representatives to describe modeling practice and document an air quality planning process for California's San Joaquin Valley

### RESEARCHER, LSA Associates, Inc., Resource Policy and Economics Group **1991 - 1994**

<u>Fiscal and Economic Impacts</u>

- Compared fiscal impacts of six land use alternatives for redevelopment of a blighted portion of the City of Orange.
- Analyzed the fiscal impacts to the Town of Colma of proposed annexation and subsequent development of a 52-acre area of San Mateo County, which included a BART station.
- Performed a fiscal impact analysis of a 800-unit development in Alameda County.
- Calculated the economic impacts associated with development of commercial, industrial, hospitality and golf uses on a 1,900-acre parcel near the Sacramento Airport.
- Analyzed the economic impacts of changing natural resource management policies.
- Performed socioeconomic, cost effectiveness, public services, land use, and air quality impact analyses to satisfy state (CEQA) and federal (NEPA) requirements for environmental review

## PUBLICATIONS

Nowlan, A., Fine, J., O'Connor, T. and Burget, S. 2021. Pollution Accounting for Corporate Actions: Quantifying the Air Emissions and Impacts of Transportation System Choices Case Study: Food Freight and the Grocery Industry in Los Angeles. Sustainability 2021, 13(18), 10194; https://doi.org/10.3390/su131810194, 13 Sep.

Borlase, S., Brandao, M.., Fine, J., Kezunovic, M., and Wojszczyk, B., Chapter 2: Smart Grid Challenges and Transformations. Smart Grids: Advanced Technologies and Solutions, 2nd Ed., CRC Press. 2017.

Fine, J., George, S. & Moss, S. 2016. System reliability and environment to be helped by non-event demand response. Natural Gas & Electricity 32/11, Wiley Periodicals, Inc., (June).

Langford, H., Yan, C., Kiliccote, S., Sung, E., Piette, M.A., Fine, J., Sopher, P., and MacCracken, M., 2016. Overcoming Challenges: Demand Response and Peak Load Reduction, http://towercompanies.com/wp-content/uploads/2016/02/2014-Greenbuild-White-Paper-H08.pdf-Adobe-Acrobat-Pro.pdf USGBC, Washington D.C., USA

Fine, J., Busch, C. and R. Garderet. 2012. The upside hedge value of California's global warming policy given uncertain future oil prices. Energy Policy. 44.46–51.

Motsinger, J., Moss, S. and J. Fine. 2010. A Gold Standard for Equity in Climate Cap-and-Trade Programs. Environment Magazine. V54:(July/Aug): 35-43.

Fine, J. and D. Owen. 2005. Technocracy and Democracy: Technocracy and Democracy: Conflicts between Models and Participation in Environmental Law and Planning. Hastings Law Journal. V56(May):900-981.

Fine, J., L. Vuilleumier, S. Reynolds, P. Roth, and N. Brown. 2003. Evaluating Uncertainties in Regional Photochemical Air Quality Modeling. Annual Review of Environmental and Resources. V28 (Nov. 2003)

Roth, P.M, S.D. Ziman, and J.D. Fine. 1993. Tropospheric Ozone. Keeping Pace With Science and Engineering: Case Studies In Environmental Regulation. National Academy Of Engineering. Wash. D.C.

## REPORTS

Busch, C., Fine, J. and Meyers, A. Clean Trucks Big Bucks. EDF-Energy Innovation Joint Whitepaper. 2020. https://energyinnovation.org/wp-content/uploads/2020/06/Clean-Trucks-Big-Bucks_June_17_2020.pdf

Bilich, A., Chong, H. and Fine, J. "In the Heart of the Valley: Implications from a 104 Home Temperature Study in Huron, California". Research Manuscript. Presented at the Center for Research in Regulated Industries Western Conference, Monterrey, California June 2018.

Panfil, M. and Fine, J. "Putting Demand Response to Work for California", EDF Whitepaper. 2015.

Mohlin, K., B. Spiller, M. Badtke-Berkow, J. Fine, G. Donzelli, and C. Larose (2014). "SolaROI: Estimating Returns to Residential Solar Panels from Underlying Tariff Structures and Compensation Mechanisms", EDF Whitepaper.

Fine, J. & Salter, R. Residential Rate Design Proposal of Environmental Defense Fund. Submittal to California Public Utility Commission. R. 12-06-13. June 2013.

Fine, J., Roos, M., Copithorne, B., Lee, R., Feingold, J., and E. Stein. On-Bill Repayment: Repaying Clean Energy Investments on Utility Bills. Energy Research Roundtable. EDF for Regional Plan Association. June 2013.

Shock Proofing Society: How California's Global Warming Solutions Act (AB 32) Reduces the Economic Pain of Energy Price Shocks. Authors: J. Fine, C. Busch and R. Garderet. Environmental Defense Fund, Center for Resource Solutions and Energy Independence Now. September 2010.

Securing a Gold Standard for Equity: Methods for Crediting Residential and Small Business Emissions Reductions in Carbon Markets. Authors: J. Fine, S. Moss and J. Motsinger. Environmental Defense Fund and San Francisco Community Power. April 2010.

Left to Our Own Devices: Financing Efficiency For Small Businesses And Low-Income Families. 2010. Authors: S. Moss and J. Fine. Environmental Defense Fund. January, 2010.

Economic Modeling of Relicensing and Decommissioning Options for the Klamath Basin Hydroelectric Project. 2006. Prepared for California Energy Commission with M.Cubed. CEC-700-2006-10

Calculating Off-Grid Terrestrial Greenhouse Gas Emission Reductions. 2004. Prepared for Environmental Defense.

The Economic Benefits of Treasure Island Wetlands. 2002. Prepared for Treasure Island Wetlands Project.

Evaluation of Technical Questions Associated with Using the SNTemp Model to Study Temperature in the Burnt River, Oregon. 1998. Prepared for Environmental Defense Fund.

Evaluating the Potential For Implementing A Tradable Discharge Permit Program in the Deschutes Drainage Basin 1997. Prepared for Environmental Defense Fund and Deschutes Basin Resources Conservancy

Estimation of the Fair Market Value of a Water Storage Contract Proposed for Sale to the United States. Memo Report. 1997. Prepared for Environmental Defense Fund.

Spatial Representativeness of Monitoring Sites and Zones of Influence of Emissions Sources. 1998. California Regional Particulate Air Quality Study 1995 Integrated Monitoring Study Data Analysis. Prepared for the San Joaquin Valley-wide Air Pollution Study Agency.

San Joaquin Valley Source Signature Scoping Study Initial Phase Findings Report. 1996. Prepared for the San Joaquin Valley Air Pollution Study Agency Technical Advisory Committee.

Feasibility of Identifying the Influence of Biogenic Emissions on Air Quality in the San Francisco Bay Area. 1996. Prepared for the Western States Petroleum Association & the BAAQMD.

Felling the Myth: The Role of Timber in the Economy of California's Sierra Nevada. 1995. Prepared for the Natural Resources Defense Council.

The Potential for Further Regulation of Nitrogen Oxides Emissions. 1995. Prepared for the Coerr Envir. Corp.

Public Finance of Surface Transportation in the Chicago Metropolitan Area in 1990. 1995. Prepared for the Environmental Defense Fund.

Northwest Orange Land Use Alternatives Fiscal Impact Analysis. 1994. Prepared for the City of Orange Community Development Department.

Cost Effectiveness Analyses for the Environmental Assessments of the Moss Landing Marine Laboratory and Watsonville Community Hospital Relocations. 1994. Prepared for Federal Emergency Mgmt. Agency.

Clean Water Act Section 404(b)(1) Alternatives Analysis for the Gelsar Property. 1994. Prepared for Gelsar and the U.S. Army Corps of Engineers.

An Economic Profile and Analysis of the Relative Importance of Mining in the California Desert Conservation Region. 1993. Prepared for The Wilderness Society.

Native Monterey Pine Forest Inventory and Sustainability Evaluation. 1993. Prepared for the Pebble Beach Company Real Estate Division.

A Review of Selected Multi-Resource Forest Planning Models. 1993. Prepared for The Pacific Forest Trust.

Socioeconomic Impact Analysis for the Environmental Assessment of the proposed Natural Gas Line Number 6902. 1993. Prepared for The Gas Company.

Mitigation Monitoring and Financial Assurance Programs for the Forward Inc. Landfill Use Permit and Modification Environmental Impact Report. 1993. Prepared for the San Joaquin County Community Development Department.

Robert's Landing Residential Development Fiscal Impact Analysis. 1992. Prepared for the City of San Leandro Planning and Building Department.

Socioeconomic Impact Analysis for the Environmental Impact Report on the proposed Anaheim Enterprise Zone. 1992. Prepared for the City of Anaheim.

Colma BART Study Area Fiscal Impact Analysis. 1992. Prepared for the Town of Colma.

Metro Air Park Development Economic Impacts Assessment. 1992. Prepared for The O'Connell Corporation.

# EXHIBIT JF-2

## JOBS AND ECONOMIC BENEFITS TO KENTUCKY FROM DPV, UTILITY SOLAR, NATURAL GAS, AND COAL ADDITIONAL GENERATION CAPACITY

# JOBS AND ECONOMIC BENEFITS TO KENTUCKY FROM DPV, UTILITY SOLAR, NATURAL GAS, AND COAL ADDITIONAL GENERATION CAPACITY

**8/21/2025**

**Authored by Richard McCann, Alec Fleischer and James Fine**

**Q. What analysis did you conduct to estimate the benefits of distributed photovoltaic generation (DPV) to the Kentucky economy?**

A. Kentucky has lagged behind other states in installing DPV with the total number of grid-connected residential DPV installations ranking 40th of all states, comprising just 0.28% of homes. In 2022, small-scale solar accounted for 0.1% of the state's total electricity mix and all solar accounted for 0.22% of the state's electricity. Kentucky solar price declines of 47% over ten years combined with other incentives leads the Solar Energy Industry Association (SEIA) to forecast that the state will see 2,846 MW of DPV growth within the next five years – 18th amongst all states.[1] Cutting back net metering or other incentives will deal a significant blow to a burgeoning green industry just as it begins to firmly establish itself.

The analysis presented here examines the benefits to the state's economy caused by a thriving DPV industry. The jobs and investment benefits of a theoretical 500 MW of additional electrical grid capacity in Kentucky are compared for DPV, utility solar, natural gas, and coal. Jobs include all direct, indirect, and induced positions during two phases: (1) construction and installation, and (2) operations. Direct jobs are those created within the project itself (such as construction workers and installers), indirect jobs arise in supporting industries that supply goods and services to the project, and induced jobs result from the

[1] SEIA State Solar Spotlight, Kentucky, https://www.seia.org/sites/default/files/2024-03/Kentucky.pdf. Note this estimate was made prior to the elimination of federal solar tax incentives.

broader economic activity generated when workers spend their earnings in the local economy. Earnings represent total employee compensation, including wages and salaries. Output is the total value of production, reflecting all goods and services generated. Value added measures the contribution to state gross state product (GSP) or statewide net income, including wages, business income, and taxes, all net of expenses. *Value added or GSP is considered the best single indicator of net economic benefit.*

This growth scenario was analyzed using the Jobs and Economic Development Impact modeling (JEDI) tool created by the National Renewable Energy Laboratory (NREL).[2] JEDI modeling impacts are state specific and generator type specific. Default JEDI model inputs were used except for specific inputs which are listed in the appendix along with a brief explanation.

**Q. What are your findings on the economic benefits?**

A. Figures KYRC-1 and KYRC-2 compare the construction and installation phases of a 500 MW capacity addition across generation types. DPV produces the largest economic boost by a wide margin, creating over 13,600 jobs and generating $753 million in earnings, nearly $2 billion in output, and more than $1.15 billion in value added or added GSP. This is accompanied by a strong 76% share of local spending, meaning most of the investment stays within the community.

By contrast, coal construction generates around 4,200 jobs and $462 million in added GSP with 30% local spending, while utility-scale solar provides 2,700 jobs and $211 million in added GSP with a slightly higher 31% local spend. Natural gas shows the

[2] NREL, "Jobs & Economic Development Impact Models," https://www.nrel.gov/analysis/jedi/, retrieved December 2023. (The JEDI model is based on the widely-used IMPLAN Regional Economic Impacts Model.)

smallest short-term impact, with only about 1,260 jobs and 28% local spending. Overall, DPV is the most beneficial technology in the construction phase as measured by job creation, local spending percentage, total earnings, total output, and total value-added indicators.

**Figure KYRC-1**

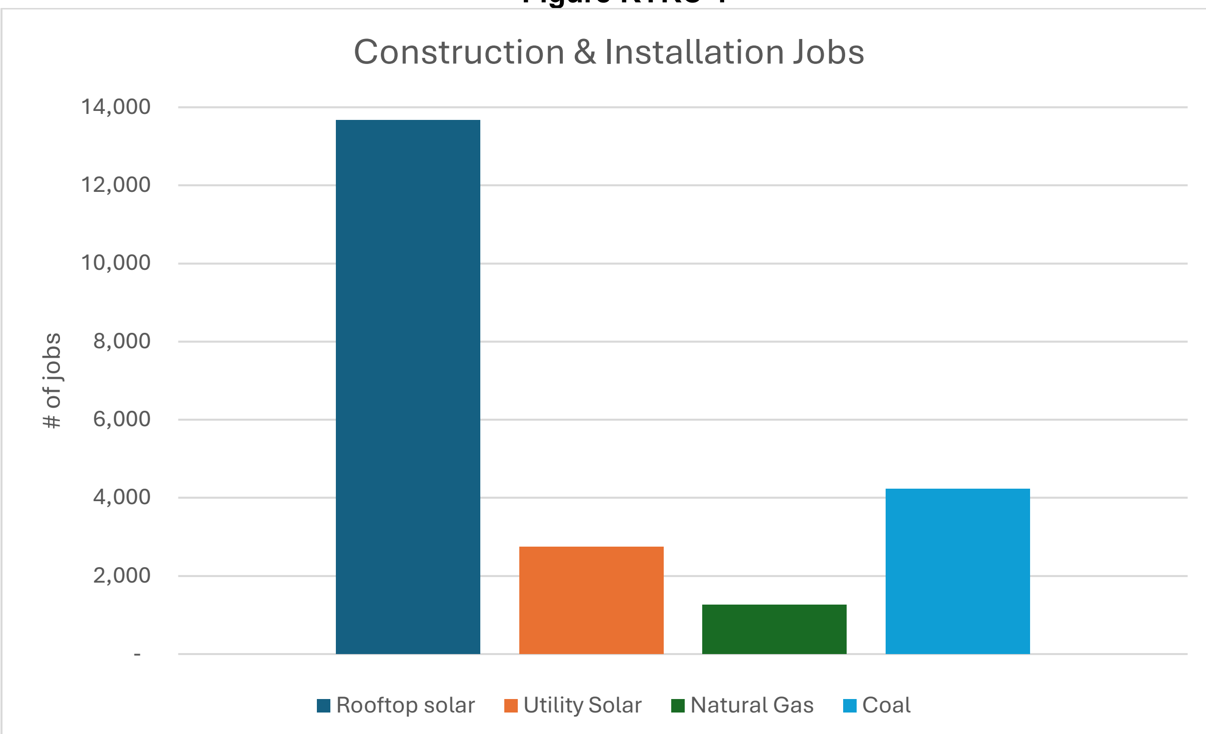



**Figure KYRC-1.** Jobs created during construction and installation of a 500 MW capacity addition. DPV supports more than 13,600 jobs, far exceeding coal, utility solar, and natural gas.

**Figure KYRC-2**

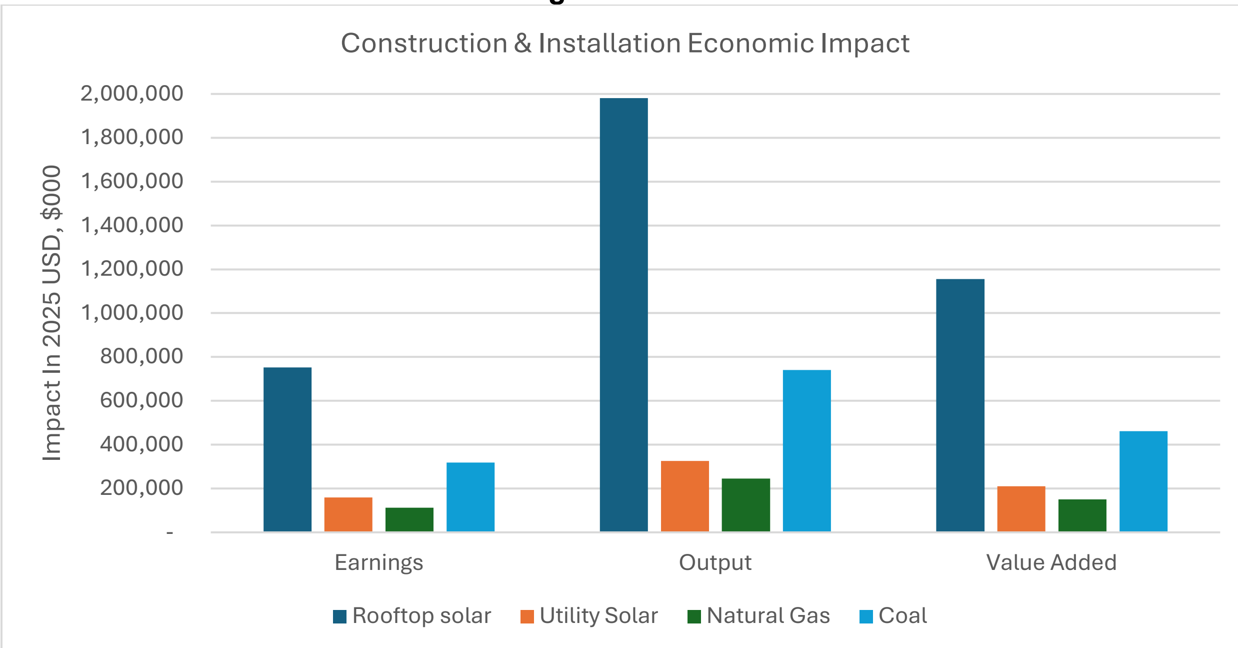



**Figure KYRC-2.** Construction and installation economic impacts of a 500 MW capacity addition by technology. DPV produces the largest benefits by far, generating $753 million in earnings, nearly $2 billion in output, and $1.16 billion in value added. Coal ranks second in all categories, followed by utility-scale solar and natural gas.

In the operating years, the results for each year are smaller but they accrue over many years to be significant as shown in Figures KYRC-3 and KYRC-4. Like the first phase, rooftop and utility solar continue to outperform fossil fuels on local benefits. DPV sustains 209 jobs with $16 million in added GSP and 91% of spending retained locally, while utility solar supports 134 jobs with $10 million in added GSP and an even higher 92% local spending share. Coal supports 171 jobs and $17 million in added GSP, slightly higher than DPV, but only 18% of that spending remains local. Natural gas performs the weakest, with just 67 jobs, $6 million in added GSP, and only 3% of spending local. These results underscore that while coal delivers somewhat higher operating-year output, solar technologies, especially rooftop, maximize long-term local economic benefits.

**Figure KYRC-3**

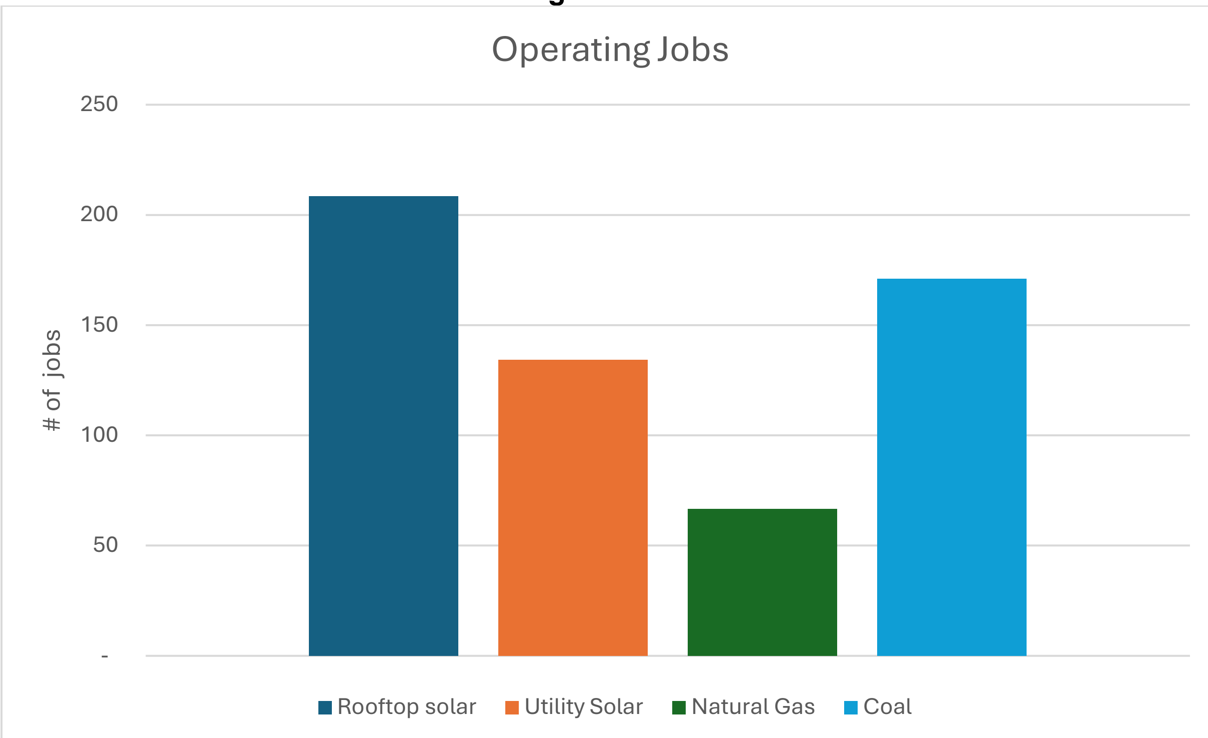



**Figure KYRC-3.** Jobs supported annually during operating years of a 500 MW capacity addition. DPV sustains about 209 jobs, utility solar 134, coal 171, and natural gas 67.

**Figure KYRC-4**

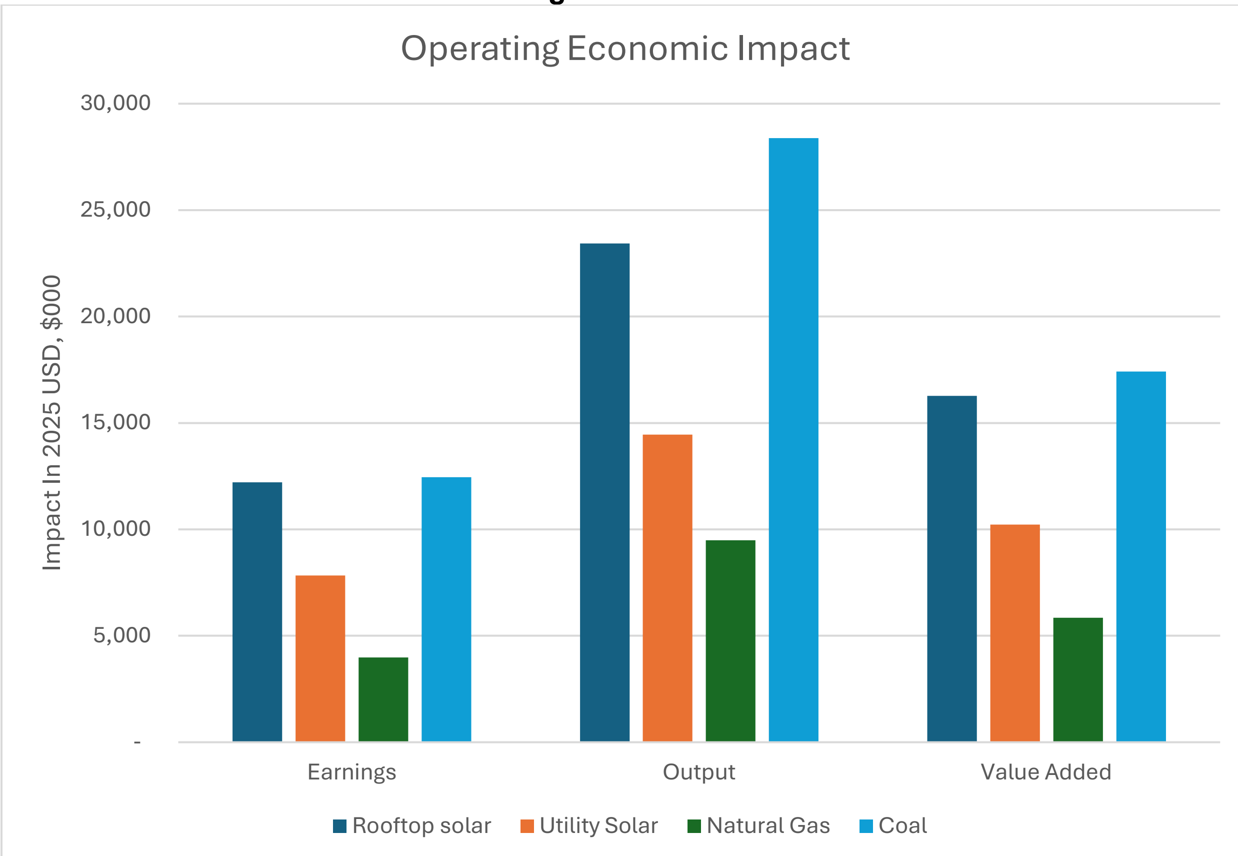



**Figure KYRC-4.** Operating economic impacts of a 500 MW capacity addition by technology. DPV sustains about $12 million in earnings, $23 million in output, and $16 million in value added each year. Coal shows significantly higher output and higher earnings and value added than DPV. Utility solar delivers moderate benefits, while natural gas provides the lowest impacts in all metrics.

**Q. What are the net economic benefits of adding DPV over relying on grid-scale solar?**

A. The net economic benefits of adding DPV over relying on grid-scale solar are significantly greater for Kentucky. While both technologies generate clean electricity, DPV produces far stronger local economic impacts. During construction, DPV supports nearly five times as many jobs as utility solar (13,664 vs. 2,744) and generates much higher earnings, output, and value added. Just as importantly, 76% of construction spending for DPV stays in Kentucky compared to only 31% for utility-scale solar. In the operating years, DPV continues to provide higher levels of employment and economic activity (209 jobs vs. 134 for utility solar), with more than 90% of ongoing spending retained in the local economy. These results show that DPV not only delivers greater total economic benefits but also ensures that the majority of those benefits circulate within Kentucky communities, maximizing long-term local economic development.

**Q. What are the net economic benefits of adding DPV compared to relying on natural gas?**

A. The net economic benefits of adding DPV over relying on natural gas are substantial. For a 500 MW capacity addition, DPV generates more than ten times the construction-phase jobs of natural gas (13,664 vs. 1,264) and produces far greater earnings ($753 million vs. $112 million), output ($1.98 billion vs. $246 million), and value added ($1.16 billion vs. $151 million). DPV also retains a much higher share of spending within Kentucky (76% vs. 28%). During operating years, DPV continues to outperform gas, supporting more than triple the jobs (209 vs. 67) and over twice the value added ($16 million vs. $6 million) while keeping 91% of spending local, compared to just 3% for natural gas. These findings demonstrate that DPV yields much larger overall economic benefits and keeps more of those benefits in Kentucky.

**Q. What are the net economic benefits of adding DPV over relying on coal?**

A. The net economic benefits of adding DPV over relying on coal are significantly higher. During construction, DPV supports more than three times as many jobs as coal (13,664 vs. 4,233) and delivers greater earnings ($753 million vs. $319 million), output ($1.98 billion vs. $740 million), and value added ($1.16 billion vs. $462 million). DPV also retains a much larger share of spending within Kentucky (76% vs. 30%). In the operating years, coal supports a slightly lower number of jobs (171 vs. 209 for DPV) and somewhat higher output and value added, but these benefits are offset by coal's much lower local spending retention (18% vs. 91% for DPV). Taken together, DPV generates larger short-term construction benefits and ensures far more of the long-term economic value remains within Kentucky communities.

Figure KYRC-5 shows how adding DPV keeps much more of the economic activity benefits in-state compared to the other technologies.

**Figure KYRC-5**

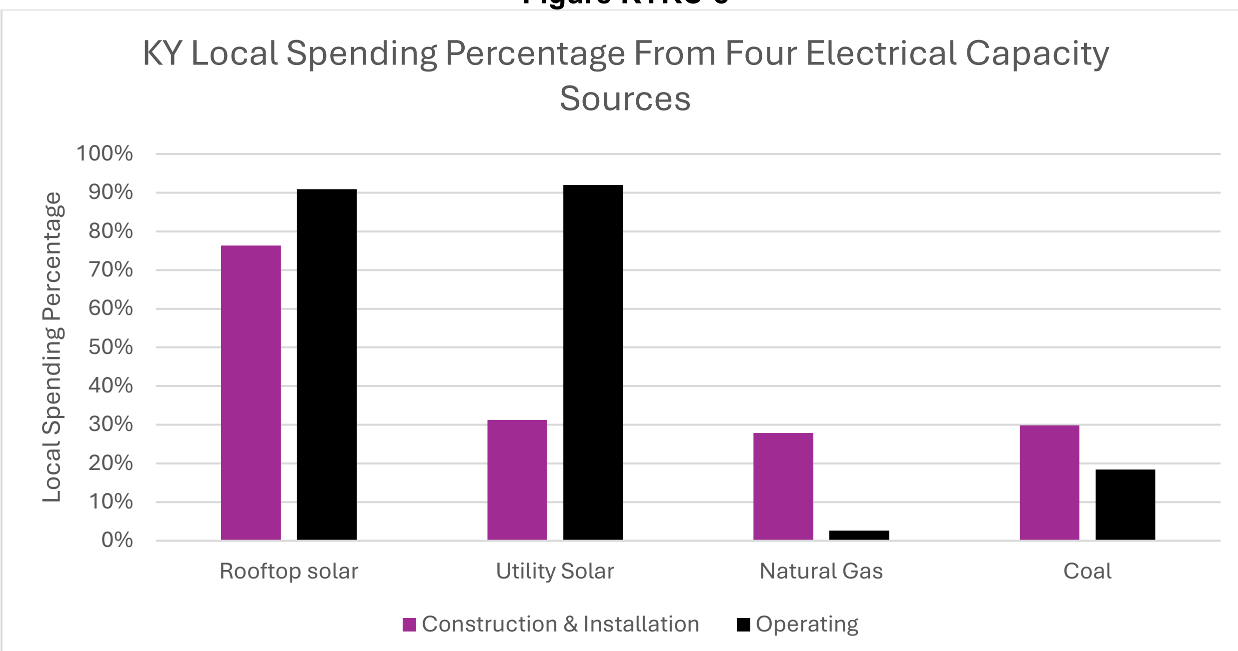



**Figure 5.** Local spending percentages during construction and operating years for a 500 MW capacity addition in Kentucky. During construction, DPV keeps the highest share of spending local (76%), while fossil fuel projects see less than one-third retained in Kentucky. Rooftop and utility solar retain the overwhelming majority of economic activity in-state during operations (91% and 92%, respectively), compared to just 18% for coal and 3% for natural gas.

**VERIFICATION**

The undersigned, James David Fine, being first duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that the information contained therein is true and correct to the best of his information, knowledge, and belief, after reasonable inquiry.

__James David Fine_______________

James David Fine

Commonwealth of Virginia
County of Prince William

Subscribed and sworn to before me by James David Fine this 29th day of August, 2025.

______________________________
Notary Public

My commission expires: 01/31/2027

COMMONWEALTH OF VIRGINIA • ELECTRONIC NOTARY PUBLIC
N

**Emma Jean Bland**

REGISTRATION NUMBER
7558382
COMMISSION EXPIRES
**January 31, 2027**

Electronic Notary Public
Notarized remotely online using communication technology via Proof.