COMMONWEATH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC TARIFF FILING OF KENTUCKY	**)**	**CASE NO.**
UTILITIES COMPANY FOR APPROVAL OF AN	**)**	**2022-00371**
ECONOMIC DEVELOPMENT RIDER SPECIAL	**)**	
CONTRACT WITH BITIKI-KY, LLC.	**)**	

TESTIMONY OF CHELSEA HOTALING

ON BEHALF OF JOINT INTERVENORS KENTUCKIANS FOR THE COMMONWEALTH, KENTUCKY SOLAR ENERGY SOCIETY, MOUNTAIN ASSOCIATION, AND KENTUCKY RESOURCES COUNCIL, INC.

January 17, 2023

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I. Introductions & Qualifications

Q. Please state for the record your name and business address.

A. My name is Chelsea Hotaling. My business address is 30 Court Street, Canton, NY 13617.

Q. By whom are you employed and in what position?

A. I am a Consultant at Energy Futures Group ("EFG"), a consulting firm that provides specialized expertise on energy efficiency and renewable energy markets, program design, power system planning, and energy policy.

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

A. I am testifying on behalf of Kentuckians for the Commonwealth ("KFTC"), Kentucky Solar Energy Society ("KYSES"), Mountain Association ("MA"), and Kentucky Resources Council ("KRC") (collectively ("Joint Intervenors").

Q. Please describe your educational background.

A. I received a Bachelor's Degree in Accounting and Economics from Elmira College. I also received a Master's in Business Administration, a Master's in Data Analytics, and a Master's in Environmental Policy from Clarkson University.

Q. Please describe your professional background.

A. I have worked for seven years in electric utility regulation and related fields. I have reviewed over a dozen integrated resource plans (IRPs) and related filings by utilities located in Arizona, Colorado, Kansas, Kentucky, Iowa, Indiana, Michigan, Missouri, Montana, Minnesota, New Mexico, Nova Scotia, Puerto Rico, and South Carolina. I have performed my own capacity expansion and production cost modeling in numerous cases, and I have reviewed planning modeling based on multiple models including EnCompass, Aurora, PLEXOS, PowerSimm, and System Optimizer. A copy of my curriculum vitae is attached as Appendix A.

Q: Have you previously filed expert witness testimony in other proceedings before this Commission or before other regulatory commissions?

A: While I have not filed testimony before the Kentucky Public Service Commission ("Commission"), I have provided expert testimony to the Colorado Public Utilities Commission, the Michigan Public Service Commission, and the Iowa Utilities Board.

Q. What is the purpose of your testimony?

A. EFG was retained by the Joint Intervenors to assist in the evaluation of the Electronic Tariff Filing of Kentucky Utilities Company ("KU") for Approval of An Economic Development Rider Special Contract with Bitiki-KY, LLC ("Special Contract") filed on October 7, 2022. The purpose of my testimony is to provide my evaluation of KU's Marginal Cost of Service Study provided in support of KU's filing.

II. Summary of Recommendations

Q. Please summarize the request in this proceeding.

A. KU is requesting approval of the Special Contract between KU and Bikiti-KY, LLC. The Special Contract is for Bitiki to receive service under the Economic Development Rider ("EDR") and the Retail Transmission Service ("RTS") for 13 megawatts ("MW") of capacity. In qualifying for the EDR, Bitiki has stated that it plans to invest $25 million in its facilities, creating approximately five new jobs.[1] If the Special Contract is approved by the Commission, Bitiki would receive service under the EDR for an initial term of 10 years.

[1] Special Contract Economic Development Rider, page 2.

For the first 12 months, the demand charges shall be reduced for the first five consecutive 12 monthly billings, beginning with 50% in the first year, and decreased by 10% per year thereafter until the sixth year of consecutive billing, which will have full total demand charges applied.

Q. Please summarize your findings and recommendations in this case

A. Based upon my review of the Marginal Cost of Service Study, I have identified some recommendations to improve the study and ensure that it is accurately determining KU's marginal costs. These recommendations include:

- Relying on costs that reflect the full anticipated costs of the new generation asset at the time the Marginal Cost of Service Study is developed.
- Consideration of the customer's load factor to inform whether the coincidence factor should be applied to the marginal demand and transmission costs.
- Incorporation of the appropriate loss-factor to the marginal demand, energy, and transmission costs.

Q. How is the remainder of your testimony organized?

A. In the remainder of my testimony, I discuss aspects of KU's 2021 IRP, 2022 CPCN Filing, and the Marginal Cost of Service Study.

III. KU's 2021 IRP and December 2022 CPCN Filing

Q. Did KU's 2021 IRP identify the year in which the Companies will have a capacity need?

A. Yes, KU identified 2028 as the year in which the summer reserve margin will fall below the 17% reserve margin requirement.

Q. How did KU identify 2028 as the first year with a capacity need?

A. In the 2021 IRP, KU modeled an early retirement date of 2028 for Mill Creek 2 and Brown 3. Once those units are removed from KU's resource portfolio, the total resources in KU's system are less than the net load projection and the summer reserve margin falls below the 17% requirement.

Q. Was a Combined Cycle ("CC") without Carbon Capture and Sequestration ("CCS") included in the modeling of new resources for KU's 2021 IRP?

A. No, the IRP that KU filed did not include a CC without CCS. Figure 1 below shows the new dispatchable resources that were included in the modeling for KU's 2021 IRP. In the IRP KU stated that "Based on the Biden administration's energy policy and the national focus on moving to clean energy, the current environment does not support the installation of NGCC without CCS due to its CO_2 emissions."[2]

Figure 1. Dispatchable Supply Side Resources Modeled in the IRP[3]

	SCCT	NGCC w/CCS	Battery Storage	
			4-hour	**8-hour**
Summer Capacity (MW)[37]	220	513	1+	1+
Winter Capacity (MW)[37]	248	539	1+	1+
Heat Rate (MMBtu/MWh)[38]	9.7	7.2	N/A	N/A
Capital Cost ($/kW)[38]	885	2,304	1,274	2,300
Fixed O&M ($/kW-yr)[38]	22	69	32	58
Firm Gas Cost ($/kW-yr)[39]	22	22	N/A	N/A
Variable O&M ($/MWh)[38]	5.24	6.08	N/A	N/A
Fuel Cost ($/MWh)	27.45	20.23	N/A	N/A

[2] 2021 IRP Vol I at 5-39 to 5-40.
[3] 2021 IRP Vol I at 5-40, Table 5-15.

Q. Has KU filed a Certificate of Public Convenience and Necessity ("CPCN") since the IRP was filed?

A. Yes, KU filed a CPCN application with the Commission on December 15, 2022, in Case No. 2022-00402.

Q. Are new natural gas-fired combined cycle units included in the CPCN application?

A. Yes, KU seeking approval for two 1-on-1 natural gas-fired combined cycle units (621 MW each).[4] Upon review of the filing, it is my understanding that these NGCC units do not include CCS.

IV. Marginal Cost of Service Study

Q. What information did you review related to the Marginal Cost of Service Study?

A. I reviewed the Marginal Cost Study from the Prime Group included with KU''s application along with workbooks KU provided in discovery responses to the Joint Intervenors and Staff.

Q. When was the Marginal Cost of Service Study completed?

A. The Marginal Cost of Service Study reports a date of August 12, 2022.

Q. What costs were reported in the Marginal Cost of Service Study?

A. The Marginal Cost of Service Study reported three components of cost including the production demand, the production energy, and transmission. The numbers calculated for each category are shown in Table 1 below.

[4] Direct Testimony of David Sinclair, pages 9-10. Case No. 2022-00402.

Table 1. Marginal Cost of Service Summary for LG&E and KU[5]

	LG&E	KU
Production Demand (per kW of Added NCP* Demand)	$2.32	$2.32
Production Energy (per kWh of Added Energy)	$0.03447	$0.03447
Transmission (per kW of Added NCP* Demand)	$0.06	$0.01

**Non-coincident peak*

Q. How were each of the costs reported in the Marginal Cost of Service Study developed?

A. The production demand calculation was based on the change in cost of advancing the new generating asset identified for the capacity need in 2028 by one year to a 2027 in-service date. For this analysis, the new generating asset evaluated was a CC. As discussed in the Marginal Cost of Service Study, the change in cost was calculated by the Economic Carrying Charge, which is the "[…] the economic cost of advancing or delaying the present value of revenue requirements associated with capital expenditures."[6] The marginal energy production cost was calculated by taking the average of the 2023 forecasted production cost data for the KU system. The marginal transmission cost was calculated based on the transmission forecast contained in the Companies' 2022 Business Plan from 2023 through 2032.

Q. How were the costs reported in the Marginal Cost of Service Study used to evaluate the KU-Bitiki contract?

A. In its response to Staff Question 2.4, KU provided a workbook that compared the annual base rate revenue from Bitiki, inclusive of the five year EDR demand charge discount. These revenues were then compared against the annual marginal energy, production, and

[5] The Prime Group Marginal Cost of Service Study, Table ES-1, page 2.
[6] The Prime Group Marginal Cost of Service Study, page 9.

transmission costs for serving Bitiki's load. As referenced in the Marginal Cost of Service Study, the "Companies will demonstrate with each special contract filing that the discounted rates exceed the marginal cost associated with serving the customer."[7]

Q. Are the marginal costs presented by KU lower than the projected revenue for the KU-Bitiki contract?

A. The analysis provided by KU in response to Staff Question 2.4 indicates that the annual projected revenue from Bitiki is larger than the annual marginal costs in each year of the ten-year contract period except for year one.

Q. Setting aside any discrepancies between the resources modeled in the 2021 IRP and the Marginal Cost of Service Study, do you have recommendations on the Marginal Cost of Service Study put forward by KU in this proceeding?

A. Yes, I have three recommendations related to the costs included for the production demand, the application of coincident peak factors, and the inclusion of loss factors in the marginal cost calculations. I will take each of these items in turn.

1. Production Demand Cost

As it relates to the cost information used to develop the production demand marginal cost, KU based this calculation on the \$951/kW[8] capital cost of a Combined Cycle ("CC") unit for 2028. The reported source of the capital cost of the CC is from the 2020 NREL ATB[9]. The analysis for the production demand marginal cost is based on accelerating the capital cost of adding a CC in 2028 to 2027. However, it does not seem that all costs of bringing

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[7] The Prime Group Marginal Cost of Service Study, page 3.
[8] As reported on page 2 of Attachment B to the Prime Group Marginal Cost of Service Study.
[9] NREL (National Renewable Energy Laboratory). 2020. "2020 Annual Technology Baseline."

a new CC online were included. In the Marginal Cost of Service Study, it was noted that "Because the fixed O&M expenses were negligible[10] in comparison to the asset costs, they were not included in the analysis."[11] Another cost category that did not seem to be considered is the cost of firm gas transport for a new gas CC. As shown in Figure 1, there was consideration for firm gas transport costs[12] for new thermal resources evaluated in the 2021 IRP. In its 2026/2027 Cost of New Entry ("CONE") Report[13], the regional transmission organization, PJM, included assumptions for the cost of firm gas transport for the reference[14] resource used in that study, which is a CC[15]. In the report, it states:

> […] we assume that the CC will obtain firm transportation service to ensure fuel supply during tight market conditions. Based on confidential data provided by PJM, nearly all new gas-fired plants that entered the market since the 2026/2027 BRA obtain firm transportation service to ensure adequate fuel supply. Based on these trends, we updated our assumption from the 2018 PJM CONE study for the CC reference to obtain firm gas supply across all CONE areas. The costs of firm transportation service are incurred annually, so we include these costs as fixed operations and maintenance costs […].[16]

However, costs associated with firm gas transport did not seem to be incorporated into the production demand marginal cost. Nor does the Company include any costs associated with interconnection of the new unit.

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[10] The NREL 2020 ATB reports a fixed O&M expense of $13/kW-year.
[11] The Prime Group Marginal Cost of Service Study, page 9.
[12] Footnote 39 states "Firm gas transportation costs are based on the cost of firm gas transportation for Cane Run 7 and the Trimble County SCCTs." 2021 IRP Vol I at 5-40, Footnote 39.
[13] PJM CONE 2026/2027 Report. Prepared by The Brattle Group and Sargent & Lundy. April 21, 2022. Retrieved from https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx
[14] Within the report one of the recommendations is for "[…] PJM, its stakeholders, and the states within the PJM footprint continue to monitor the viability of building new gas-fired resources and, if needed, consider developing a clean reference resource cost estimate", page v.
[15] The language in the report on page iv says "A common misconception is that by selecting a reference resource, PJM promotes the development of that specific type of resource. In fact, other technologies may enter alongside the reference resource or instead of the reference resource, depending on which resources are most competitive and/or enjoy policy support."
[16] PJM CONE 2026/2027 Report, page 25.

I also question the use of the NREL ATB as a source for the capital costs of the CC used in the Marginal Cost of Service Study since KU is seeking to build two new CCs in their Certificates of Public Convenience and Necessity[17] ("CPCN") application pending before this Commission. KU would have reasonably known[18] the cost of those CCs in advance of this filing and could have updated the marginal cost study. In its CPCN filing, KU is asking for approval of two 1-on-1 natural gas-fired combined cycle units (621 MW each).[19] For that proceeding, KU sought bids for new resources through a Request for Proposal ("RFP") and KU's Project Engineering group provided the only responses for fossil fuel resources. [20] Furthermore, the CPCN application indicates that firm gas transportation services are being explored for the proposed NGCC units[21] and that there will be transmission upgrade costs[22] associated with retirements and replacement with the NGCC units at the sites.[23] Since KU possesses the information about costs for the two NGCC resources they are seeking CPCN approval for, the underlying cost used in the Marginal Cost Study should have been based on this information and incorporated all costs for bringing a new CC online, including capital, fixed O&M, firm gas transport, and projected transmission upgrades. The cost information for the NGCC resources in the CPCN proceeding would appear to be the most up to date cost information that KU would have to inform the costs that are used in the Marginal Cost of Service Study, especially when the production demand costs are based on the costs of building a new CC.

[17] Case No. 2022-00402 filed on December 15, 2022.
[18] Witness Schram reports that the RFP was released on June 22, 2022, page 4. Case No. 2022-00402.
[19] Direct Testimony of David Sinclair, pages 9-10. Case No. 2022-00402.
[20] Direct Testimony of Charles Schram, page 5. Case No. 2022-00402.
[21] Direct Testimony of Charles Schram, page 12. Case No. 2022-00402.
[22] Exhibit SAW-1. 2022 Resource Assessment. Table 35, page 55. Case No. 2022-00402
[23] Reported costs of $35,035,000 for retirement of Mill Creek 1-2 and Brown 3 and replacement with a NGCC at Mill Creek. Exhibit SAW-1. 2022 Resource Assessment. Table 35, page 55. Case No. 2022-00402

When asked by Staff in discovery about the use of the incremental net metering cost based rates from Case No. 2020-00349, KU responded to Staff:

> *First, setting aside KU's other reservations of record about the approach the Commission adopted in Case No. 2020-00349 to set NMS-2 rates, the information used to calculate those rates is now stale. The more current data used in the marginal cost study is more appropriate to use to estimate marginal costs of service today and for the next five years.*[24]

KU's response to Staff seems to indicate the desire to use current data for the analysis which aligns with the recommendation I have made about using current cost information in the Marginal Cost of Service Study.

Irrespective of the question on whether the generation asset evaluated in the Marginal Cost of Service Study aligns with the most recently filed IRP, the costs used in the Marginal Cost of Service Study should incorporate the full costs that KU is assuming for the NGCC resources included in the CPCN filing.

2. Coincidence Factor Application

The second recommendation I have related to the Marginal Cost Study is the application of a non-coincident peak factor to the production demand and the transmission costs. KU's coincidence factor is based on "a simple average of the relationship between the NCP[25] and CP[26] demands for the TOD and RTS rate classes. Those classes represent the most likely customers who would be eligible for the Economic Development Rider."[27] This average coincidence factor calculated by KU is 60.27%. Information in Bitiki's application reported that "Based on the customer 2MW pilot project, they expect their load factor to

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[24] KU's response to Staff's Question 1.5. Case No. 2022-00371.
[25] Non-coincident peak.
[26] Coincident peak.
[27] KU response to Joint Intervenors Question 2.9. Case No. 2022-00371.

be above 99%. During the winter months fans may be slightly reduced dropping the overall load roughly 2.5% from peak."[28] Workbooks provided by KU to Staff in discovery[29] indicate a load factor of 95% was assumed for Bitiki in the projection of annual revenues and marginal costs. Given this level of load, it would seem more reasonable to not apply the coincidence factor to the marginal demand or transmission cost so that those costs would be represented on a coincident peak basis. In its response to Staff Question 1.3, KU seems to agree with the higher load factor, as they responded with "But KU agrees that for very high load factor customers like Bitiki who do not have an agreement for interruptible service it is reasonable to apply the CP marginal transmission cost rather than the NCP cost."[30]

3. Application of the Loss-Factor to the Marginal Cost of Demand, Energy and Transmission

The Marginal Cost Study noted that the marginal production demand cost value, the marginal energy cost value, and the marginal transmission cost value should be adjusted to "reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage."[31] After reviewing the supporting workbooks for the Marginal Cost of Service Study, it was not clear what loss-factor was applied and how it was incorporated into the analysis. When asked about the loss-factor applied in the analysis, it appears that KU is acknowledging that the loss-factors were not applied:

> *Note that even when applying the line loss factors above to the Marginal Cost Analysis, Bitiki's revenues (including Fuel Adjustment Clause and Environmental Surcharge adjustment clause revenues) still exceed Bitiki's marginal costs in every*

[28] Attachment 3 to Response to Joint Intervenors Question 1.4, page 11. Case No. 2022-00371.
[29] Workbook named "03_-_KU_DR2_PSC_Attach_to_Q04_-_10-Year_Revenue_to_Marginal_Cost"
[30] KU response to Staff Question 1.3. Case No. 2022-00371.
[31] The Prime Group Marginal Cost of Service Study, page 6 and 10.

> *year of the EDR Contract, and Bitiki will contribute over $8.8 million to energy and demand-related fixed costs over 10 years (Base Rate Revenue minus Marginal Costs).* [32]

In the response to Joint Intervenors Question 2.12, KU provided the loss factor for the transmission level, which is 1.03295.[33] My recommendation is that the appropriate loss factor should be included in all marginal cost calculations performed by KU.

Q. If KU implemented all the recommendations you have made related to the Marginal Cost of Service Study, would that result in a change to the projection that Bitiki's annual revenues will continue to be above the annual marginal costs?

A. Since KU has redacted[34] the RFP information in the CPCN proceeding, I cannot say how the costs associated with the bid for the CCs compare to the capital cost from the 2020 NREL ATB. I suspect there would be difference in costs due to the supply chain and inflationary pressures experienced since the 2020 NREL ATB was released, but without seeing the confidential information on the bid prices in the CPCN proceeding, I cannot be certain. Not applying the coincidence factor to the marginal production demand and the transmission costs would result in higher costs for those two categories. Incorporating the loss factor for the marginal demand, energy, and transmission would also increase those marginal costs.

[32] KU response to Joint Intervenors Question 2.12. Case No. 2022-00371.
[33] KU response to Joint Intervenors Question 2.12. Case No. 2022-00371.
[34] Redacted RFP information includes Exhibit CRS-2 and Exhibit SAW-1.

Q. If the recommendations do not make Bitiki's revenue fall short of the marginal cost of serving Bitiki, does that mean that KU should ignore the recommendations for evaluation of future EDR contracts and Marginal Cost of Service Studies?

A. No, the recommendations I have made stand regardless of whether or not they change the favorability of the economics for the KU-Bitiki contract. These are recommendations that should be considered and incorporated into the Marginal Cost of Service Studies used in the evaluation of all EDR contracts.

V. Recommendation for the Bitiki-KY, LLC Special Contract

Q. What recommendations do you have for the Commission on the Marginal Cost of Service Study and evaluating special contracts?

A. I recommend that the Marginal Cost of Service Study should incorporate the following three recommendations:

- Use current cost information that reflects the full anticipated costs of the new generation asset at the time the Marginal Cost of Service Study is developed.
- Consideration of the customer's load factor to inform whether the coincidence factor should be applied to the marginal demand and transmission costs.
- Incorporation of the appropriate loss-factor to the marginal demand, energy, and transmission costs.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

The undersigned, Chelsea Hotaling, being first duly sworn, deposes and says that she 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 her information, knowledge, and belief, after reasonable inquiry.

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Subscribed and sworn to before me by CHELSEA HOTALING this 16 day of 01, 2023.

____

Notary Public

My commission expires: 04/14/2024

NOTARY PUBLIC STATE OF TEXAS

Tonnesha Fears
Notary Public, State of Texas
Comm. Expires 04-14-2024
Notary ID 132436988

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This document is signed by

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Appendix A

Chelsea Hotaling
Consultant

ENERGY FUTURES GROUP

Professional Summary

Chelsea is a Consultant at Energy Futures Group specializing in integrated resource planning and load forecasting. Prior to joining EFG, Chelsea held a research position at Clarkson University while completing her Master's in Data Analytics and Environmental Policy & Governance. Chelsea's research focused on multi-stakeholder microgrids for resiliency. She also participated in the Reforming the Energy Vision (REV) proceedings for the Potsdam (NY) microgrid REV project. Chelsea's current work is focused on all aspects of Integrated Resource Planning including capacity expansion and production cost modeling and load forecasting. Chelsea runs the EnCompass model in support of long-term planning exercises such an IRP analyses and has critiqued IRP modeling performed using Aurora, Plexos, PowerSimm, and System Optimizer. Chelsea has experience working with numerous software programs including Python, R, and Stata.

Education

M.S., Data Analytics, Clarkson University, 2020

M.S., Environmental Policy and Governance, Clarkson University, 2019

MBA, Concentration in Environmental Management, Clarkson University, 2012

B.S., Accounting and Economics, Elmira College, 2007

Experience

2021-present: Consultant, Energy Futures Group, Hinesburg, VT

2020-2021: Senior Analyst, Energy Futures Group, Hinesburg, VT

2019-2020: Analyst, Energy Futures Group, Hinesburg, VT

2018-2019: Intern, Sommer Energy, Canton, NY

2016-2019: Research Assistant, Clarkson University, Potsdam, NY

Selected Projects

- GridLab. Performing capacity expansion and production cost modeling within EnCompass to identify resource mixes to achieve 100% emissions-free electricity by 2035 for the Public Service Company of New Mexico's electric system. (2022 to present)
- Sierra Club. Performing capacity expansion and production cost modeling within EnCompass to evaluate retirement and replacement of MidAmerican's coal plants (2022 to present)

Energy Futures Group, Inc

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- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association. Reviewed and provided comments on East Kentucky Power Cooperative's 2022 Integrated Resource Plan. (2022)
- Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association. Reviewed and provided comments on Louisville Gas & Electric and Kentucky Utilities' 2021 Integrated Resource Plan. (2022)
- The Department of Attorney General and Sierra Club. Reviewed and submitted testimony on the Aurora modeling Indiana Michigan Power Company performed for its 2021 IRP. (2022)
- The Environmental Law and Policy Center, The Ecology Center, Union of Concerned Scientists, and Vote Solar. Performed Aurora modeling to evaluate higher levels of distributed solar for the Consumers Energy Company's 2021 Integrated Resource Plan. (2020 to 2021)
- Colorado Office of the Utility Consumer Advocate. Performed EnCompass modeling related to the Public Service Company of Colorado's 2021 Electric Resource Plan. (2021)
- Minnesota Center for Environmental Advocacy. Evaluation of Otter Tail Power's 2021 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2022 to present) Evaluation of Minnesota Power's 2021 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2021 to present) Evaluation of Xcel Energy's 2020 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2019 to 2021)
- Earthjustice**.** Evaluation of Louisville Gas and Electric Company and Kentucky Utilities Company Integrated Resource Plan. (2022 to present) Evaluation of PREPA's request for proposals for temporary emergency generation. (May 2020) Evaluation of the Puerto Rico Electric Power Authority's 2019 Integrated Resource Plan. (2019 to 2020)
- The Council for the New Energy Economics. Participated in Evergy's integrated resource plan stakeholder workshops and performed EnCompass modeling to evaluate coal plant retirements (2020 to 2021).
- EfficiencyOne. Supported EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to 2020)
- Southern Alliance for Clean Energy. Evaluation of Dominion Energy South Carolina's 2020 Integrated Resource Plan. (2020)
- Washington Electric Cooperative. Conducted the analysis for the 2020 Integrated Resource Plan. (2019 to 2020)
- Coalition for Clean Affordable Energy**.** Evaluated the Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station and performed EnCompass modeling to develop an alternative replacement portfolio. (2019 to 2020)
- Citizens Action Coalition of Indiana. Comments regarding Duke Energy Indiana's integrated resource plans to meet future energy and capacity needs (May 2022). Comments regarding Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (March 2022) Comments regarding Southern Indiana Gas and Electric's integrated resource plans to meet future energy and capacity needs (November 2020). Comments regarding Indianapolis Power and Light's integrated resource plans to meet future energy and capacity needs

(April 2020). Comments regarding Indiana Michigan Power Company's integrated resource plans to meet future energy and capacity needs (December 2019).

- Institute for Energy Economics and Financial Analysis (IEEFA). Evaluation of National Grid's long-term natural gas capacity report. (March 2020) Evaluation of the Puerto Rico Energy Commission's proposed wheeling regulation. (March 2019) Co-author for the report Retail Choice Will Not Bring Down Puerto Rico's High Electricity Rates. (August 2018) Evaluation of the Puerto Rico Energy Commission's proposed microgrid rules. (February 2018)

Publications

Hotaling, C., Bird, S., & Heintzelman, M. D. (2021). Willingness to pay for microgrids to enhance community resilience. Energy Policy, 154, 112248.

Atems, B., & Hotaling, C. (2018). The effect of renewable and nonrenewable electricity generation on economic growth. Energy Policy, 112, 111-118.

Bird, S., & Hotaling, C. (2017). Multi-stakeholder microgrids for resilience and sustainability. Environmental Hazards, 16(2), 116-132.

Bird, S., Enayati, A., Hotaling, C., and Ortmeyer, T. (2017). Resilient Community Microgrids: Governance and Operational Challenges. In Energy Internet: An Open Energy Platform to Transform Legacy Power Systems into Open Innovation and Global Economic Engine, edited by Alex Q. Huang and Wencong Su. Elsevier.