Qualifications of

JONATHAN F. WALLACH

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.

1989–90 **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.

1987–88 **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).

1981–86 **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

“The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities” (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

“The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets” (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

“The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities” (with Paul Chernick), *1996 Summer Study on Energy Efficiency in Buildings* 7(7.47–7.55). Washington: American Council for an Energy-Efficient Economy, 1996.

“Retrofit Economics 201: Correcting Common Errors in Demand-Side-Management Cost-Benefit Analysis” (with John Plunkett and Rachael Brailove). In proceedings of “Energy Modeling: Adapting to the New Competitive Operating Environment,” conference sponsored by the Institute for Gas Technology in Atlanta in April of 1995. Des Plaines, Ill.: IGT, 1995.

“The Transfer Loss is All Transfer, No Loss” (with Paul Chernick), *Electricity Journal* 6:6 (July, 1993).

“Benefit-Cost Ratios Ignore Interclass Equity” (with Paul Chernick et al.), *DSM Quarterly*, Spring 1992.

“Consider Plant Heat Rate Fluctuations,” *Independent Energy*, July/August 1991.

“Demand-Side Bidding: A Viable Least-Cost Resource Strategy” (with Paul Chernick and John Plunkett), *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“New Tools on the Block: Evaluating Non-Utility Supply Opportunities With *The Power Analyst*, (with John Plunkett), *Proceedings of the Fourth National Conference on Micro-computer Applications in Energy*, April 1990.

REPORTS

“Economic Benefits from Early Retirement of Reid Gardner” (with Paul Chernick) prepared for and filed by the Sierra Club in PUC of Nevada Docket No. 11-08019.

“Green Resource Portfolios: Development, Integration, and Evaluation” (with Paul Chernick and Richard Mazzini) report to the Green Energy Coalition presented as evidence in Ontario EB 2007-0707.

“Risk Analysis of Procurement Strategies for Residential Standard Offer Service” (with Paul Chernick, David White, and Rick Hornby) report to Maryland Office of People’s Counsel. 2008. Baltimore: Maryland Office of People’s Counsel.

“Integrated Portfolio Management in a Restructured Supply Market” (with Paul Chernick, William Steinhurst, Tim Woolf, Anna Sommers, and Kenji Takahashi). 2006. Columbus, Ohio: Office of the Ohio Consumers’ Counsel.

“First Year of SOS Procurement.” 2004. Prepared for the Maryland Office of People’s Counsel.

"Energy Plan for the City of New York" (with Paul Chernick, Susan Geller, Brian Tracey, Adam Auster, and Peter Lanzalotta). 2003. New York: New York City Economic Development Corporation.

"Peak-Shaving–Demand-Response Analysis: Load Shifting by Residential Customers" (with Brian Tracey). 2003. Barnstable, Mass.: Cape Light Compact.

"Electricity Market Design: Incentives for Efficient Bidding; Opportunities for Gaming." 2002. Silver Spring, Maryland: National Association of State Consumer Advocates.

"Best Practices in Market Monitoring: A Survey of Current ISO Activities and Recommendations for Effective Market Monitoring and Mitigation in Wholesale Electricity Markets" (with Paul Peterson, Bruce Biewald, Lucy Johnston, and Etienne Gonin). 2001. Prepared for the Maryland Office of People's Counsel, Pennsylvania Office of Consumer Advocate, Delaware Division of the Public Advocate, New Jersey Division of the Ratepayer Advocate, Office of the People's Counsel of the District of Columbia.

"Comments Regarding Retail Electricity Competition." 2001. Filed by the Maryland Office of People's Counsel in U.S. FTC Docket No. V010003.

"Final Comments of the City of New York on Con Edison's Generation Divestiture Plans and Petition." 1998. Filed by the City of New York in PSC Case No. 96-E-0897.

"Response Comments of the City of New York on Vertical Market Power." 1998. Filed by the City of New York in PSC Case Nos. 96-E-0900, 96-E-0098, 96-E-0099, 96-E-0891, 96-E-0897, 96-E-0909, and 96-E-0898.

"Preliminary Comments of the City of New York on Con Edison's Generation Divestiture Plan and Petition." 1998. Filed by the City of New York in PSC Case No. 96-E-0897.

"Maryland Office of People's Counsel's Comments in Response to the Applicants' June 5, 1998 Letter." 1998. Filed by the Maryland Office of People's Counsel in PSC Docket No. EC97-46-000.

"Economic Feasibility Analysis and Preliminary Business Plan for a Pennsylvania Consumer's Energy Cooperative" (with John Plunkett et al.). 1997. 3 vols. Philadelphia, Penn.: Energy Coordinating Agency of Philadelphia.

"Good Money After Bad" (with Charles Komanoff and Rachel Brailove). 1997. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

"Maryland Office of People's Counsel's Comments on Staff Restructuring Report: Case No. 8738." 1997. Filed by the Maryland Office of People's Counsel in PSC Case No. 8738.

"Protest and Request for Hearing of Maryland Office of People's Counsel." 1997. Filed by the Maryland Office of People's Counsel in PSC Docket Nos. EC97-46-000, ER97-4050-000, and ER97-4051-000.

"Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests" (with Paul Chernick, Susan Geller, John Plunkett, Roger Colton, Peter Bradford, Bruce Biewald, and David Wise). 1997. Baltimore, Maryland: Maryland Office of People's Counsel.

"Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire's Electric-Utility Industry" (with Bruce Biewald and Paul Chernick). 1996. Concord, N.H.: NH OCA.

"Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities" (with Paul Chernick, Susan Geller, Rachel Brailove, and Adam Auster). 1996. On behalf of the Massachusetts Attorney General (Boston).

"Report on Entergy's 1995 Integrated Resource Plan." 1996. On behalf of the Alliance for Affordable Energy (New Orleans).

"Preliminary Review of Entergy's 1995 Integrated Resource Plan." 1995. On behalf of the Alliance for Affordable Energy (New Orleans).

"Comments on NOPSI and LP&L's Motion to Modify Certain DSM Programs." 1995. On behalf of the Alliance for Affordable Energy (New Orleans).

"Demand-Side Management Technical Market Potential Progress Report." 1993. On behalf of the Legal Environmental Assistance Foundation (Tallahassee)

"Technical Information." 1993. Appendix to "Energy Efficiency Down to Details: A Response to the Director General of Electricity Supply's Request for Comments on Energy Efficiency Performance Standards" (UK). On behalf of the Foundation for International Environmental Law and Development and the Conservation Law Foundation (Boston).

"Integrating Demand Management into Utility Resource Planning: An Overview." 1993. Vol. 1 of "From Here to Efficiency: Securing Demand-Management Resources" (with Paul Chernick and John Plunkett). Harrisburg, Pa.:Pennsylvania Energy Office

"Making Efficient Markets." 1993. Vol. 2 of "From Here to Efficiency: Securing Demand-Management Resources" (with Paul Chernick and John Plunkett). Harrisburg, Pa.: Pennsylvania Energy Office.

"Analysis Findings, Conclusions, and Recommendations." 1992. Vol. 1 of "Correcting the Imbalance of Power: Report on Integrated Resource Planning for Ontario Hydro" (with Paul Chernick and John Plunkett).

"Demand-Management Programs: Targets and Strategies." 1992. Vol. 1 of "Building Ontario Hydro's Conservation Power Plant" (with John Plunkett, James Peters, and Blair Hamilton).

"Review of the Elizabethtown Gas Company's 1992 DSM Plan and the Demand-Side Management Rules" (with Paul Chernick, John Plunkett, James Peters, Susan Geller, Blair Hamilton, and Andrew Shapiro). 1992. Report to the New Jersey Department of Public Advocate.

"Comments of Public Interest Intervenors on the 1993–1994 Annual and Long-Range Demand-Side Management and Integrated Resource Plans of New York Electric Utilities" (with Ken Keating et al.) 1992.

“Review of Jersey Central Power & Light’s 1992 DSM Plan and the Demand-Side Management Rules” (with Paul Chernick et al.). 1992. Report to the New Jersey Department of Public Advocate.

“Review of Rockland Electric Company’s 1992 DSM Plan and the Demand-Side Management Rules” (with Paul Chernick et al.). 1992.

“Initial Review of Ontario Hydro’s Demand-Supply Plan Update” (with David Argue et al.). 1992.

“Comments on the Utility Responses to Commission’s November 27, 1990 Order and Proposed Revisions to the 1991–1992 Annual and Long Range Demand Side Management Plans” (with John Plunkett et al.). 1991.

“Comments on the 1991–1992 Annual and Long Range Demand-Side-Management Plans of the Major Electric Utilities” (with John Plunkett et al.). Filed in NY PSC Case No. 28223 in re New York utilities’ DSM plans. 1990.

“Profitability Assessment of Packaged Cogeneration Systems in the New York City Area.” 1989. Principal investigator.

“Statistical Analysis of U.S. Nuclear Plant Capacity Factors, Operation and Maintenance Costs, and Capital Additions.” 1989.

“The Economics of Completing and Operating the Vogtle Generating Facility.” 1985. ESRG Study No. 85-51A.

“Generating Plant Operating Performance Standards Report No. 2: Review of Nuclear Plant Capacity Factor Performance and Projections for the Palo Verde Nuclear Generating Facility.” 1985. ESRG Study No. 85-22/2.

“Cost-Benefit Analysis of the Cancellation of Commonwealth Edison Company’s Braidwood Nuclear Generating Station.” 1984. ESRG Study No. 83-87.

“The Economics of Seabrook 1 from the Perspective of the Three Maine Co-owners.” 1984. ESRG Study No. 84-38.

“An Evaluation of the Testimony and Exhibit (RCB-2) of Dr. Robert C. Bushnell Concerning the Capital Cost of Fermi 2.” 1984. ESRG Study No. 84-30.

“Electric Rate Consequences of Cancellation of the Midland Nuclear Power Plant.” 1984. ESRG Study No. 83-81.

“Power Planning in Kentucky: Assessing Issues and Choices—Project Summary Report to the Public Service Commission.” 1984. ESRG Study No. 83-51.

“Electric Rate Consequences of Retiring the Robinson 2 Nuclear Plant.” 1984. ESRG Study No. 83-10.

“Power Planning in Kentucky: Assessing Issues and Choices—Conservation as a Planning Option.” 1983. ESRG Study No. 83-51/TR III.

"Electricity and Gas Savings from Expanded Public Service Electric and Gas Company Conservation Programs." 1983. ESRG Study No. 82-43/2.

"Long Island Without the Shoreham Power Plant: Electricity Cost and System Planning Consequences; Summary of Findings." 1983. ESRG Study No. 83-14S.

"Long Island Without the Shoreham Power Plant: Electricity Cost and System Planning Consequences; Technical Report B—Shoreham Operations and Costs." 1983. ESRG Study No. 83-14B.

"Customer Programs to Moderate Demand Growth on the Arizona Public Service Company System: Identifying Additional Cost-Effective Program Options." 1982. ESRG Study No. 82-14C.

"The Economics of Alternative Space and Water Heating Systems in New Construction in the Jersey Central Power and Light Service Area, A Report to the Public Advocate." 1982. ESRG Study No. 82-31.

"Review of the Kentucky-American Water Company Capacity Expansion Program, A Report to the Kentucky Public Service Commission." 1982. ESRG Study No. 82-45.

"Long Range Forecast of Sierra Pacific Power Company Electric Energy Requirements and Peak Demands, A Report to the Public Service Commission of Nevada." 1982. ESRG Study No. 81-42B.

"Utility Promotion of Residential Customer Conservation, A Report to Massachusetts Public Interest Research Group." 1981. ESRG Study No. 81-47

PRESENTATIONS

"Office of People's Counsel Case No. 9117" (with William Fields). Presentation to the Maryland Public Utilities Commission in Case No. 9117, December 2008.

"Electricity Market Design: Incentives for Efficient Bidding, Opportunities for Gaming." NASUCA Northeast Market Seminar, Albany, N.Y., February 2001.

"Direct Access Implementation: The California Experience." Presentation to the Maryland Restructuring Technical Implementation Group on behalf of the Maryland Office of People's Counsel. June 1998.

"Reflecting Market Expectations in Estimates of Stranded Costs," speaker, and workshop moderator of "Effectively Valuing Assets and Calculating Stranded Costs." Conference sponsored by International Business Communications, Washington, D.C., June 1997.

EXPERT TESTIMONY

1989 **Mass. DPU** on behalf of the Massachusetts Executive Office of Energy Resources. Docket No. 89-100. Joint testimony with Paul Chernick relating to statistical analysis of U.S. nuclear-plant capacity factors, operation and maintenance costs, and capital additions; and to projections of capacity factor, O&M, and capital additions for the Pilgrim nuclear plant.

1994 **NY PSC** on behalf of the Pace Energy Project, Natural Resources Defense Council, and Citizen's Advisory Panel. Case No. 93-E-1123. Joint testimony with John Plunkett critiques proposed modifications to Long Island Lighting Company's DSM programs from the perspective of least-cost-planning principles.

Vt. PSB on behalf of the Vermont Department of Public Service. Docket No. 5270-CV-1 and 5270-CV-3. Testimony and rebuttal testimony discusses rate and bill effects from DSM spending and sponsors load shapes for measure- and program-screening analyses.

1996 **New Orleans City Council** on behalf of the Alliance for Affordable Energy. Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.

New Orleans City Council Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.; Alliance for Affordable Energy. April, 1996.

Prudence of utilities' IRP decisions; costs of utilities' failure to follow City Council directives; possible cost disallowances and penalties; survey of penalties for similar failures in other jurisdictions.

1998 **Massachusetts Department of Telecommunications and Energy** Docket No. 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Paul Chernick, January, 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

Massachusetts Department of Telecommunications and Energy Docket No. 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Paul Chernick, October, 1998. Joint surrebuttal with Paul Chernick, January, 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

1999 **Maryland PSC** Case No. 8795, Delmarva Power & Light comprehensive restructuring agreement, Maryland Office of People's Counsel. July 1999.

Support of proposed comprehensive restructuring settlement agreement

Maryland PSC Case Nos. 8794 and 8808, Baltimore Gas & Electric Company comprehensive restructuring agreement, Maryland Office of People's Counsel. Initial Testimony July 1999; Reply Testimony August 1999; Surrebuttal Testimony August 1999.

Support of proposed comprehensive restructuring settlement agreement

Maryland PSC Case No. 8797, comprehensive restructuring agreement for Potomac Edison Company, Maryland Office of People's Counsel. October 1999.

Support of proposed comprehensive restructuring settlement agreement

Connecticut DPUC Docket No. 99-03-35, United Illuminating standard offer, Connecticut Office of Consumer Counsel. November 1999.

Reasonableness of proposed revisions to standard-offer-supply energy costs. Implications of revisions for other elements of proposed settlement.

2000 **U.S. FERC** Docket No. RT01-02-000, Order No. 2000 compliance filing, Joint Consumer Advocates intervenors. Affidavit, November 2000.

Evaluation of innovative rate proposal by PJM transmission owners.

2001 **Maryland PSC** Case No. 8852, Charges for electricity-supplier services for Potomac Electric Power Company, Maryland Office of People's Counsel. March 2001.

Reasonableness of proposed fees for electricity-supplier services.

Maryland PSC Case No. 8890, Merger of Potomac Electric Power Company and Delmarva Power and Light Company, Maryland Office of People's Counsel. September 2001; surrebuttal, October 2001. In support of settlement: Supplemental, December 2001; rejoinder, January 2002.

Costs and benefits to ratepayers. Assessment of public interest.

Maryland PSC Case No. 8796, Potomac Electric Power Company stranded costs and rates, Maryland Office of People's Counsel. December 2001; surrebuttal, February 2002.

Allocation of benefits from sale of generation assets and power-purchase contracts.

2002 **Maryland PSC** Case No. 8908, Maryland electric utilities' standard offer and supply procurement, Maryland Office of People's Counsel. Direct, November 2002; Rebuttal December 2002.

Benefits of proposed settlement to ratepayers. Standard-offer service. Procurement of supply.

2003 **Maryland PSC** Case No. 8980, adequacy of capacity in restructured electricity markets; Maryland Office of People's Counsel. Direct, December 2003; Reply December 2003.

Purpose of capacity-adequacy requirements. PJM capacity rules and practices. Implications of various restructuring proposals for system reliability.

2004 **Maryland PSC** Case No. 8995, Potomac Electric Power Company recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental March 2004, Surrebuttal April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8994, Delmarva Power & Light recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8985, Southern Maryland Electric Coop standard-offer service; Maryland Office of People's Counsel. Direct, July 2004.

Reasonableness and risks of resource-procurement plan.

2005 **FERC** Docket No. ER05-428-000, revisions to ICAP demand curves; City of New York. Statement, March 2005.

Net-revenue offset to cost of new capacity. Winter-summer adjustment factor. Market power and in-City ICAP price trends.

FERC Docket No. PL05-7-000, capacity markets in PJM; Maryland Office of People's Counsel. Statement, June 2005.

Inefficiencies and risks associated with use of administratively determined demand curve. Incompatibility of four-year procurement plan with Maryland standard-offer service.

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Coalition of Consumers for Reliability, Affidavit October 2005, Supplemental Affidavit October 2006.

Inefficiencies and risks associated with use of administratively determined demand curve. Effect of proposed reliability-pricing model on capacity costs.

2006 **Maryland PSC** Case No. 9052, Baltimore Gas & Electric rates and market-transition plan; Maryland Office of People's Counsel, February 2006.

Transition to market-based residential rates. Price volatility, bill complexity, and cost-deferral mechanisms.

Maryland PSC Case No. 9056, default service for commercial and industrial customers; Maryland Office of People's Counsel, April 2006.

Assessment of proposals to modify default service for commercial and industrial customers.

Maryland PSC Case No. 9054, merger of Constellation Energy Group and FPL Group; Maryland Office of People's Counsel, June 2006.

Assessment of effects and risks of proposed merger on ratepayers.

Illinois Commerce Commission Docket No. 06-0411, Commonwealth Edison Company residential rate plan; Citizens Utility Board, Cook County State's Attorney's Office, and City of Chicago, Direct July 2006, Reply August 2006.

Transition to market-based rates. Securitization of power costs. Rate of return on deferred assets.

Maryland PSC Case No. 9064, default service for residential and small commercial customers; Maryland Office of People's Counsel, Rebuttal Testimony, September 2006.

Procurement of standard-offer power. Structure and format of bidding. Risk and cost recovery.

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Maryland Office of the People's Counsel, Supplemental Affidavit October 2006.

Distorting effects of proposed reliability-pricing model on clearing prices. Economically efficient alternative treatment.

Maryland PSC Case No. 9063, optimal structure of electric industry; Maryland Office of People's Counsel, Direct Testimony, October 2006; Rebuttal November 2006; surrebuttal November 2006.

Procurement of standard-offer power. Risk and gas-price volatility, and their effect on prices and market performance. Alternative procurement strategies.

Maryland PSC Case No. 9073, stranded costs from electric-industry restructuring; Maryland Office of People's Counsel, Direct Testimony, December 2006.

Review of estimates of stranded costs for Baltimore Gas & Electric.

2007 **Maryland PSC** Case No. 9091, rate-stabilization and market-transition plan for the Potomac Edison Company; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Rate-stabilization plan.

Maryland PSC Case No. 9092, rates and rate mechanisms for the Potomac Electric Power Company; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9093, rates and rate mechanisms for Delmarva Power & Light; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9099, rate-stabilization plan for Baltimore Gas & Electric; Maryland Office of People's Counsel, Direct, March 2007; Surrebuttal April 2007.

Review of standard-offer-service-procurement plan. Rate stabilization plan.

Connecticut DPUC Docket No. 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony June 2007.

Assessment of proposed capacity contracts.

Maryland PSC Case No. 9117, residential and small-commercial standard-offer service; Maryland Office of People's Counsel. Direct and Reply, September 2007; Supplemental Reply, November 2007; Additional Reply, December 2007; presentation, December 2008.

Benefits of long-term planning and procurement. Proposed aggregation of customers.

Maryland PSC Case No. 9117, Phase II, residential and small-commercial standard-offer service; Maryland Office of People's Counsel. Direct, October 2007.

Energy efficiency as part of standard-offer-service planning and procurement. Procurement of generation or long-term contracts to meet reliability needs.

2008 **Connecticut DPUC 08-01-01**, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Paul Chernick), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

Ontario EB-2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Paul Chernick and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

2009 **Maryland PSC** Case No. 9192, Delmarva Power & Lights rates; Maryland Office of People's Counsel. Direct, August 2009; Rebuttal, Surrebuttal, September 2009.

Cost allocation and rate design.

Wisconsin PSC Docket No. 6630-CE-302, Glacier Hills Wind Park certificate; Citizens Utility Board of Wisconsin. Direct and Surrebuttal, October 2009.

Reasonableness of proposed wind facility.

PUC of Ohio Case No 09-906-EL-SSO, standard-service-offer bidding for three Ohio electric companies; Office of the Ohio Consumers' Counsel. Direct, December 2009.

Design of auctions for SSO power supply. Implications of migration of First-Energy from MISO to PJM.

2010 **PUC of Ohio** Case No 10-388-EL-SSO, standard-service offer for three Ohio electric companies; Office of the Ohio Consumers' Counsel. Direct, July 2010.

Design of auctions for SSO power supply.

Maryland PSC Case No. 9232, Potomac Electric Power Co. administrative charge for standard-offer service; Maryland Office of People's Counsel. Reply, Rebuttal, August 2010.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Maryland PSC Case No. 9226, Delmarva Power & Light administrative charge for standard-offer service; Maryland Office of People's Counsel. Reply, Rebuttal, August 2010.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Maryland PSC Case No. 9221, Baltimore Gas & Electric cost recovery; Maryland Office of People's Counsel. Reply, August 2010; Rebuttal, September 2010; Surrebuttal, November 2010

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Wisconsin PSC Docket No. 3270-UR-117, Madison Gas & Electric gas and electric rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, Surrebuttal, September 2010.

Standby rate design. Treatment of uneconomic dispatch costs.

Nova Scotia UARB Case No. NSUARB P-887(2), fuel-adjustment mechanism; Nova Scotia Consumer Advocate. Direct, September 2010.

Effectiveness of fuel-adjustment incentive mechanism.

Manitoba PUB, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystems. Direct, December 2010.

Assessment of drought-related financial risk.

2011 **Mass. DPU 10-170,** NStar–Northeast Utilities merger; Cape Light Compact. Direct, May 2011.

Merger and competitive markets. Competitively neutral recovery of utility investments in new generation.

Mass. DPU 11-5, -6, -7, NStar wind contracts; Cape Light Compact. Direct, May 2011.

Assessment of utility proposal for recovery of contract costs.

Wisc. PSC Docket No. 4220-UR-117, electric and gas rates of Northern States Power: Citizens Utility Board of Wisconsin. Direct, Rebuttals (2) October 2011; Surrebuttal, Oral Sur-Surrebutal November 2011;

Cost allocation and rate design. Allocation of DOE settlement payment.

Wisc. PSC Docket No. 6680-FR-104, fuel-cost-related rate adjustments for Wisconsin Power and Light Company: Citizens Utility Board of Wisconsin. Direct, October 2011; Rebuttal, Surrebuttal, November 2011

Costs to comply with Cross State Air Pollution Rule.

2012 **Maryland PSC** Case No. 9149, Maryland IOUs' development of RFPs for new generation; Maryland Office of People's Counsel. March 2012.

Failure of demand-response provider to perform per contract. Estimation of cost to ratepayers.

PUCO Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, 11-350-EL-AAM, transition to competitive markets for Columbus Southern Power Company and Ohio Power Company; Ohio Consumers' Counsel. May 2012

Structure of auctions, credits, and capacity pricing as part of transition to competitive electricity markets.

Wisconsin PSC Docket No. 3270-UR-118, Madison Gas & Electric rates, Wisconsin Citizens Utility Board. Direct, August 2012; Rebuttal, September 2012.

Cost allocation and rate design (electric).

Wisconsin PSC Docket No. 05-UR-106, We Energies rates, Wisconsin Citizens Utility Board. Direct, Rebuttal, September 2012.

Cost allocation and rate design (electric).

Wisconsin PSC Docket No. 4220-UR-118, Northern States Power rates, Wisconsin Citizens Utility Board. Direct, Rebuttal, October 2012; Surrebuttal, November 2012.

Recovery of environmental remediation costs at a manufactured gas plant. Cost allocation and rate design.

2013 **Corporation Commission of Oklahoma** Cause No. PUD 201200054, Public Service Company of Oklahoma environmental compliance and cost recovery, Sierra Club. Direct, January 2013; rebuttal, February 2013; surrebuttal, March 2013.

Economic evaluation of alternative environmental-compliance plans. Effects of energy efficiency and renewable resources on cost and risk.

Maryland PSC Case No. 9324, Starion Energy marketing, Maryland Office of People's Counsel. September 2013.

Estimation of retail costs of electricity supply.

Wisconsin PSC Docket No. 6690-UR-122, Wisconsin Public Service Corporation gas and electric rates, Wisconsin Citizens Utility Board. Direct, August 2013; Rebuttal, Surrebuttal September 2013.

Cost allocation and rate design; rate-stabilization mechanism.

Wisconsin PSC Docket No. 4220-UR-119, Northern States Power Company gas and electric rates, Wisconsin Citizens Utility Board. Direct, Rebuttal, Surrebuttal, October 2013.

Cost allocation and rate design.

Michigan PSC Case No. U-17429, Consumers Energy Company approval for new gas plant, Natural Resources Defense Council. Corrected Direct, October 2013.

Need for new capacity. Economic assessment of alternative resource options.

2014 **Maryland PSC** Case Nos. 9226 & 9232, administrative charge for standard-offer service; Maryland Office of People's Counsel. Reply, April 2014; surrebuttal, May 2014.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Conn. PURA Docket No. 13-07-18, rules for retail electricity markets; Office of Consumer Counsel. Direct, April 2014.

Estimation of retail costs of power supply for residential standard-offer service.

PUC Ohio Case Nos. 13-2385-EL-SSO, 13-2386-EL-AAM; Ohio Power Company standard-offer service; Office of the Ohio Consumers' Counsel. Direct, May 2014.

Allocation of distribution-rider costs.

Wisc. PSC Docket No. 6690-UR-123, Wisconsin Public Service Corporation electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, August 2014; Surrebuttal, September 2014.

Cost allocation and rate design.

Wisc. PSC Docket No. 05-UR-107, We Energy biennial review of electric and gas costs and rates; Citizens Utility Board of Wisconsin. Direct, August 2014; Rebuttal, Surrebuttal September 2014.

Cost allocation and rate design.

Wisc. PSC Docket No. 3270-UR-120, Madison Gas and Electric Co. electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, September 2014.

Cost allocation and rate design.

Nova Scotia UARB Case No. NSUARB P-887(6), Nova Scotia Power fuel-adjustment mechanism; Nova Scotia Consumer Advocate. Evidence, December 2014.

Allocation of fuel-adjustment costs.

2015 **Maryland PSC** Case No. 9221, Baltimore Gas & Electric cost recovery; Maryland Office of People's Counsel. Second Reply, June 2015; Second Rebuttal, July 2015.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Wisconsin PSC Docket No. 6690-UR-124, Wisconsin Public Service Corporation electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, September 2015; Surrebuttal, October 2015.

Cost allocation and rate design.

Wisconsin PSC Docket No. 4220-UR-121, Northern States Power Company gas and electric rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, Surrebuttal, October 2015.

Cost allocation and rate design.

Maryland PSC Cases Nos. 9226 & 9232, administrative charge for standard-offer service; Maryland Office of People's Counsel. Third Reply, September 2015; Third Rebuttal, October 2015.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Nova Scotia UARB Case No. NSUARB P-887(7), Nova Scotia Power fuel-adjustment mechanism; Nova Scotia Consumer Advocate. Evidence, December 2015.

Accounting adjustment for estimated over-earnings. Proposal for modifying procedures for setting the Actual Adjustment.

2016 **Maryland PSC** Case No. 9406, Baltimore Gas & Electric base rate case; Maryland Office of People's Counsel. Direct, February 2016; Rebuttal, March 2016; Surrebuttal, March 2016.

Allocation of Smart Grid costs. Recovery of conduit fees. Rate design.

Nova Scotia UARB Case No. NSUARB P-887(16), Nova Scotia Power 2017-2019 Fuel Stability Plan; Nova Scotia Consumer Advocate. Direct, May 2016; Reply, June 2016.

Base Cost of Fuel forecast. Allocation of Maritime Link capital costs. Fuel cost hedging plan.

Wisconsin PSC Docket No. 3270-UR-121, Madison Gas and Electric Company electric and gas rates; Citizens Utility Board of Wisconsin. Direct, August 2016; Rebuttal, Surrebuttal, September 2016.

Cost allocation and rate design.

Wisconsin PSC Docket No. 6680-UR-120, Wisconsin Power and Light Company electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, Surrebuttal, Sur-surrebuttal, September 2016.

Cost allocation and rate design.

Minnesota PSC Docket No. E002/GR-15-826, Northern States Power Company electric rates; Clean Energy Organizations. Direct, June 2016; Rebuttal, September 2016; Surrebuttal, October 2016.

Cost basis for residential customer charges.

Nova Scotia UARB Case No. NSUARB M07611, Nova Scotia Power 2016 fuel adjustment mechanism audit; Nova Scotia Consumer Advocate. Direct, November 2016.

Sanctions for imprudent fuel-contracting practices.

2017 **Kentucky PSC** Case No. 2016-00370, Kentucky Utilities Company electric rates; Sierra Club. Direct, March 2017.

Cost basis for residential customer charges. Design of residential energy charges.

Kentucky PSC Case No. 2016-00371, Louisville Gas & Electric Company electric rates; Sierra Club. Direct, March 2017.

Cost basis for residential customer charges. Design of residential energy charges.

Massachusetts DPU 17-05, Eversource Energy electric rates; Cape Light Compact. Direct, April 2017; Supplemental Direct, Surrebuttal, August 2017.

Cost Allocation. Cost basis for residential customer charges. Demand charges for net metering customers.

Michigan PSC Case No. U-18255, DTE Electric Company electric rates; Natural Resources Defense Council, Michigan Environmental Council, and Sierra Club. Direct, August 2017.

Cost basis for residential customer charges.

North Carolina NCUC Docket No. E-2, Sub 1142, Duke Energy Progress electric rates; North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy. Direct, October 2017.

Cost basis for residential customer charges.

Indiana Utility Regulatory Commission Cause No. 44967, Indiana Michigan Power Company electric rates; Citizens Action Coalition of Indiana, Indiana Coalition for Human Services, Indiana Community Action Association, and Sierra Club. Direct, November 2017.

Cost basis for residential customer charges.

2018 **North Carolina NCUC** Docket No. E-7, Sub 1146, Duke Energy Carolinas electric rates; North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy. Direct, January 2018.

Cost basis for residential customer charges.

PUC Ohio Case Nos. 15-1830-EL-AIR, 15-1831-EL-AAM, 15-1832-EL-ATA; Dayton Power and Light Company electric rates; Natural Resources Defense Council. Direct, April 2018.

Cost basis for residential customer charges.

Indiana Utility Regulatory Commission Cause No. 45029, Indianapolis Power and Light Company electric rates; Citizens Action Coalition of Indiana, Indiana Coalition for Human Services, Indiana Community Action Association, and Sierra Club. Direct, May 2018.

Cost basis for residential customer charges. Design of residential energy rates.

PUC of Texas Docket No. 48401, Texas-New Mexico Power Company electric rates; Office of Public Utility Counsel. Direct, Cross-Rebuttal, August 2018.

Cost of service study. Allocation of requested revenue increase.

West Virginia PSC Case No. 18-0646, Appalachian Power Company and Wheeling Power Company electric rates; Consumer Advocate Division. Direct, Rebuttal, October 2018.

Cost allocation and rate design.

2019 **South Carolina PSC** Docket No. 2018-319-E, Duke Energy Carolinas electric rates; South Carolina State Conference of the NAACP, South Carolina Coastal Conservation League, and Upstate Forever. Direct, February 2019; Surrebuttal, March 2019.

Cost basis for residential customer charges.

South Carolina PSC Docket No. 2018-318-E, Duke Energy Progress electric rates; South Carolina State Conference of the NAACP, South Carolina Coastal Conservation League, and Upstate Forever. Direct, Surrebuttal, March 2019.

Cost basis for residential customer charges.

Indiana Utility Regulatory Commission Cause No. 45159, Northern Indiana Public Service Company electric rates; Citizens Action Coalition of Indiana. Direct, February 2019; Responsive, June 2019.

Proposed industrial rate restructuring. Allocation of requested revenue increase. Cost basis for residential customer charges.

Indiana Utility Regulatory Commission Cause No. 45235, Indiana Michigan Power Company electric rates; Citizens Action Coalition of Indiana and Indiana Community Action Association. Direct, August 2019; Cross-Answering, September 2019.

Proposed investment in advanced metering infrastructure. Allocation of requested revenue increase. Cost basis for residential customer charges. Design of residential energy rates. Proposed residential demand rate pilot.

Nova Scotia UARB Case No. NSUARB M09288, Nova Scotia Power 2020-2022 Fuel Stability Plan; Nova Scotia Consumer Advocate. Direct, August 2019.

Proposed residential rates for the Fuel Stability Period. Proposed treatment of excess earnings.

Indiana Utility Regulatory Commission Cause No. 45253, Duke Energy Indiana electric rates; Citizens Action Coalition of Indiana, Indiana Community Action Association, and Environmental Working Group. Direct, October 2019; Cross-Answering, December 2019.

Cost of service study. Allocation of requested revenue increase. Cost basis for residential customer charges. Design of residential energy rates. Proposed revenue decoupling mechanism.

EXHIBIT JFW-2

RATE DESIGN 23

The Customer Charge and Problems Of Double Allocation of Costs

By GEORGE J. STERZINGER

AFTER several years of the "great rate debate" attention finally seems to be turning towards a forgotten part of rate design: the customer charge. Utilities, forced by the Public Utility Regulatory Policies Act to justify or do away with declining energy charges, have begun arguing for cost classification and subsequent rate design with increasingly large customer charges. Recently proposed customer charges seem to be consistently in the $6 to $9 range, accompanied by embedded cost-of-service studies supporting even greater charges.

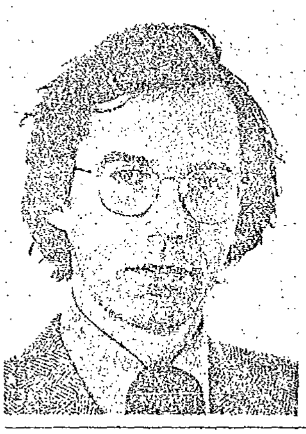
Consumer and environmental groups concerned about rate design reform (rather than using the customer charge as a place to dump costs, as the utilities do) have seen it as a place to shave costs. Concerned primarily with getting a kilowatt-hour or usage charge to reflect incremental or marginal costs more accurately, these groups have attempted to resolve the problem of the resulting excess revenue by proposing that the customer charge be lowered enough to "lose" the surplus. Negative customer charges or lump sum monthly payments from the utility to consumers have been proposed by more imaginative analysts.[1]

Analyses of the proper customer charge have often yielded contradictory results depending upon whether incremental or embedded costs were used. Incremental analyses often, but not always, support low customer charges, while embedded cost analyses often, but not always, support high customer charges.

The importance of incremental price signals and the need to strike a balance between revenue constraints and proper price signals have produced wide agreement that the customer charge is the least "informative" of all parts of a rate design and should be the last place a utility is allowed to collect revenues if incremental costs are found to be useful in designing rates.

Unfortunately, the debate on the proper definition and use of incremental costs remains unresolved, while traditional practices of embedded cost allocation seem to support very high customer charges. Regulators, forced with making a decision, have found some cost basis to be

This article is a critique of the currently most widely used methodology for classifying a portion of electric utility distribution plant as a customer cost. The author argues that this classification, combined with an allocation of the "above minimum" portion on a demand basis, leads to an overallocation of costs to low-use residential customers of the electric system.



George J. Sterzinger is an economist with the New England Regional Energy Project where he specializes in electric utility rate design testimony. In 1979 he became director of the project. The NEREP provides economic, legal, and technical assistance to low-income groups on regulatory utility issues and other energy policy matters. **Mr. Sterzinger** received a BA degree in economics from St. Joseph College, Ransselaer, Indiana, and has completed all requirements but the dissertation for a PhD degree in economics at Purdue University.

[1] "Customer Charges and the Public Utility Regulatory Policies Act," by Edward F. Renshaw and Perry Renshaw, 104 PUBLIC UTILITIES FORTNIGHTLY 17, August 30, 1979, found high customer charges contrary to the intention of PURPA.

preferable to unresolved speculation, and raised the customer charge based on embedded cost-of-service studies.

Since incremental analyses cannot by themselves support a low customer charge, the embedded cost analyses which support high customer charges must also be closely investigated to determine if they meet current objectives of rate design. An examination of these methodologies reveals the following characteristics:

— Almost all of them rely for their justification on the determination of the cost of a minimum distribution system, and the classification of this system as a customer cost.

— Once the classification has been made, it is an inescapable conclusion of the allocated cost-of-service study that calculated customer costs will be substantial.

— However, an examination of the rationale for the classification and the implications of that classification lead equally inescapably to the conclusion that minimum use residential customers will be overcharged by such cost allocation practices.

— The only reasonable remedy for the problem of overcharging is to classify the entire distribution system on a consistent basis, which would be a demand basis.

— Once this is done, traditional cost-of-service studies no longer provide support for high customer charges.

A national survey of utility practices in classification of distribution system costs determine that the great majority used some form of minimum system to classify costs in the relevant Federal Energy Regulatory Commission accounts. (The survey was conducted by Carolina Power and Light Company, Raleigh, North Carolina.) The survey summarized the results of company practices to determine how much, on average, each distribution plant account was classified as demand. The results by FERC account were as follows:

— Account 364 — Poles and fixtures were separated into primary and secondary; the primary portion was split 50-50 between customer and demand costs, the secondary portion was classified 56.5 per cent customer and 43.5 per cent demand.

— Account 365 — Conductors and devices were also separated into primary and secondary; the primary portion was classified 44.3 per cent customer and 55.7 per cent demand, and the secondary portion was classified 46.4 per cent customer and 53.6 per cent demand.

— Account 368 — Line transformers were classified 34 per cent customer and 66 per cent demand.

— Account 369 — Services were classified 70.8 per cent customer and 29.2 per cent demand.

The difficulties with these methodologies only begin with the minimum distribution system. The concept is very difficult to define and consequently susceptible to widely varying interpretations. No single method exists for calculating the cost of this system; nevertheless, a fairly standard approach is to reconstruct the existing distribution system using some type of minimum equipment. Minimum equipment could be of the type employed by the company, currently purchased by the company, currently used in the industry, or currently required by safety code. The cost of this equipment can be either booked or in current prices. Obviously, with this large a menu of definitions to choose from, a utility analyst can calculate costs for these systems over a wide range.

It should be mentioned here that one other method sometimes used to calculate the cost of a minimum system is the "zero-intercept" method whereby regression equations relating cost to various sizes of equipment are derived, and then solved for the cost of zero-sized or "zero-intercept" equipment. The strongest objections to this methodology arise from the limitations on data, the unreliability of the derived equations, and some fundamental problems that arise from making the statistical inference about the cost of the zero-sized equipment.

A typical utility in the sample discussed earlier, faced with the problem of classifying costs in Account 365 —overhead lines, for example, would determine the cost of the minimum equipment needed to replace all existing lines, calculate that cost as a fraction of the total costs of equipment in the account, and use that fraction to classify customer costs. Thus, a utility with 1,000 miles of overhead lines and two types of line costing $1 per foot and $2 per foot would calculate a minimum system cost of roughly $5.28 million ($1 × 5,280 feet per mile × 1,000 miles). This $5.28 million can, of course, be varied if different types of minimum lines are used, or if for other reasons the cost of $1 per foot is changed.

Beyond problems arising from the indeterminate nature of the minimum system, the appropriateness of classifying these costs as customer costs has been long debated. Strictly speaking, customer costs should be limited to those costs which can be shown to vary exclusively with number of customers. Distribution system costs, both as built and hypothetical minimum system, obviously depend to a great extent on geographical considerations — type of terrain and customer density. Several analysts have argued that the nature of cost causation — in this case at least in part due to geography — does not allow the costs to be neatly fit into either demand or customer cost categories; that the costs are simply unallocable. Recent statistical analyses support this notion.[2]

An additional and more severe problem with this methodology arises from the consequences of classifying distribution system costs into both customer and demand portions. Simply put, this practice leads

[2]"The Economics of Electric Distribution System Costs and Investments," by David J. Lessels, 106 PUBLIC UTILITIES FORTNIGHTLY 37, December 4, 1980, found no statistical justification for the classification of distribution costs as customer related.

inevitably to a double allocation and possibly a double collection of these costs from low-use residential customers and a misallocation of costs among customer classes.

To see why this is so, one need only step back for a moment to consider what it is that a cost allocation study attempts to do, and what happens when distribution system costs are split into customer and demand portions and then allocated to individual classes.

An allocation study assigns costs to customers on the basis of usage characteristics; fairness requires that allocated costs follow, as closely as possible, the actual costs of serving customers. Splitting the distribution system into a minimum usage and an above minimum usage portion, and allocating the minimum portion on a customer basis, and the above minimum on a usage basis results in low-use residential customers paying for more of the system than is required to serve them. By splitting the distribution system into two parts, low-use residential consumers are charged twice: once, on a customer basis, for a portion of the system sized to meet their demands; and again on a demand basis for a portion of the system sized to serve demand beyond what would be needed to serve them. The only practical way satisfactorily to assure that low-use customers are charged only once for distribution equipment is to allocate the distribution system costs on a single consistent basis. Of the two considered, customer and demand, it is obvious that only demand can be used to classify and allocate distribution costs on a satisfactory basis.

In order to explain more fully why this method constitutes double charging of low-use customers, we can look more closely at the handling of FERC Accounts 364 and 365 which represent the cost of overhead lines and poles. To illustrate this, suppose the company had only 1,000 miles of overhead lines and 10,000 poles; and in addition it used two types of line — one costing $1 per foot, for 500 miles of overhead, the other costing $2 per foot, for the remainder; and two sizes of pole — 5,000 costing $30 per pole and 5,000 costing $60 per pole. Total cost of this system would be:

a) Line: 500 miles at $1 per foot	$2,640,000	
b) Line: 500 miles at $2 per foot	5,280,000	
Subtotal		$7,920,000
c) Poles: 5,000 poles at $30 per pole	$ 150,000	
d) Poles: 5,000 poles at $60 per pole	300,000	
Subtotal		$ 450,000
Total		$8,370,000

A minimum system in this case would be determined by calculating the cost of the 1,000 miles of overheads if only the minimum-sized line was used, plus the cost of the 10,000 poles if only the minimum-sized pole was used.

Cost of the minimum system is:

a) Line: 1,000 miles at $1 per foot	$5,280,000	
b) Poles: 10,000 poles at $30 per pole	300,000	
Total		$5,580,000

Therefore, the cost of the above minimum (or capacity) system would be the remainder, or $2,780,000.

The minimum system calculated in this fashion could, and actually does, serve a considerable level of usage.

The minimum system is allocated on a customer basis — all customers are charged for an equal share of it. The remainder of the system, the more expensive facilities required to meet loads beyond those handled by minimum-sized equipment, is allocated on some demand basis; noncoincident peak demand is often used. In the calculation of the noncoincident peak demand allocation factors, usage at all levels of the residential and general service customer classes is used to determine allocation factors.

If, for example, the minimum overhead lines, conductors, and poles could supply a demand of two kilowatts per residential customer, that amount of usage would be paid for in the customer charge. In the determination of demand allocation factors, however, each residential customer's demand is calculated and added to determine the portion of the above minimum system costs to be allocated to the residential class and to each customer through the appropriate rates. So a residential customer who has a demand of two kilowatts will have paid for all the distribution costs associated with his load through the customer charge, but will also have his two-kilowatt usage go into the demand allocation factor to allocate distribution costs associated with above minimum usage.

One way to solve the double allocation problem would be to determine, for each piece of minimum equipment, the demand level it would be capable of serving, and then adjusting the demand allocation factors used to allocate the costs of all equipment of that type in order to assure that minimum use customers and the residential class were not charged twice. In many cases this would mean calculating several allocation factors for each FERC distribution account, since more than one type of equipment is used in the account. Even after overcoming all the problems of this approach one is still confronted with the dubious value of charging for equipment on an up-front basis rather than through a per kilowatt-hour charge at a time when conservation is recognized as an important goal of energy policy.

The direct way to assure that problems of overcollection are not built into the methodology used to determine class costs of service is to classify all distribution costs as demand costs. If this methodology is used in embedded cost studies, the studies will produce more equitable estimates of the cost of serving low-use residential customers.

EXHIBIT JFW-3

Duke Energy Carolinas
Response to
NCJC Data Request
Data Request No. 3

Docket No. E-7, Sub 1214

Date of Request: January 10, 2020
Date of Response: January 20, 2020

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC Data Request No. 3-3, was provided to me by the following individual(s): Kaari K. Beard, Rates & Regulatory Manager, Rate Case Planning & Execution, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

3-3. Reference Pirro Exhibit No. 4.
a) Please provide in an electronic spreadsheet with all cell formulas and file linkages intact a version of Pirro Exhibit No. 4 based on a cost of service study for the 1CP Summer scenario which classifies 100% of the costs recorded in FERC Accounts 364 through 368 as demand-related (i.e., does not classify any distribution plant costs as customer-related based on a minimum system analysis.)

Response:

In response to a) and b) i) Please see the attached file, 'NCJC DR 3-3a DEC-COS-Bund-NC-SCP-No Min Sys-PR with Pirro Exh 4' for the Summer 1CP Cost of Service – No Minimum System proposed version with the COSS tab linked to an unofficial version of the Pirro Exhibit 4 tab.
In response to b) ii) The Company does not have this data available.

NCJC DR 3-3a
DEC-COS-Bund-NC-

Excerpt from "NCJC DR 3-3a DEC-COS-Bund-NC-SCP-No Min Sys-PR with Pirro Exh 4"

DUKE ENERGY CAROLINAS, INC.
Docket No. E-7, Sub 1214
NC RETAIL COST OF SERVICE - PROPOSED - 1CP SUMMER - NO MINIMUM SYSTEM
For the test year ending December 31, 2018
Dollars in Thousands

UNOFFICIAL RATE INCREASE EXHIBIT LINKED TO COS THAT RATE DESGN USES TO PRODUCE PIRRO EXHIBIT 4

THIS IS NOT AN OFFICIAL PIRRO EXHIBIT 4

Spread of Proposed Base Rate Increase to Customer Classes

Line No.	Rate Class	Present Revenue Run: Annualized Rate Base (A)	Present Revenue Run: Present Rates Revenues Excluding Riders (B)	Present Revenue Run: Present Net Operating Income (C)	Present ROR (D)=(C)/(A)	Gross Revenues At Average ROR (E)	Variance From The Average (F)=(B)-(E)	25.0% Reduction in Variance from The Average (G)=-(F)*25%	Proposed Rate Increase Before Reduction in Variance (H)	Proposed Rate Increase After Reduction in Variance (I)=(H)+(G)	Total Adjusted Present Rates Revenues Including Riders (J) = (V) / (T)	Adjusted Proposed Percent Increase (K)=(I)/(J)	ROR at Proposed Rates (L)	Ties to Official Pirro Exh 4 Not Updated for Versions EDIT Rider (M)	Proposed Rate Increase Incl. EDIT Rider After Reduction in Variance (N)=(I)+(M)	Adjusted Proposed Percent Increase Incl. Riders (O)=(N)/(J)
1	**Rate RS**	**$ 7,663,973**	**$ 2,176,229**	**$ 446,580**	**5.8%**	**$ 2,133,712**	**$ 42,518**	**$ (10,629)**	**$ 220,696**	**$ 210,066**	**$ 2,280,641**	**9.2%**	**7.9%**	**$ (80,149)**	**$ 129,918**	**5.7%**
2	Rate RS_1	4,533,648	1,272,131	256,602	5.7%	1,256,861	15,270	(3,818)	130,553	126,736	1,330,496	9.5%	7.8%	(45,389)	81,347	6.1%
3	Rate RT	14,574	3,980	658	4.5%	4,148	(168)	42	420	462	4,224	10.9%	6.9%	(176)	286	6.8%
4	Rate RE_1	3,115,751	900,118	189,320	6.1%	872,702	27,416	(6,854)	89,723	82,869	945,921	8.8%	8.1%	(34,584)	48,285	5.1%
5	**Rate GS**	**2,643,381**	**819,190**	**171,347**	**6.5%**	**781,933**	**37,257**	**(9,314)**	**76,120**	**66,806**	**886,498**	**7.5%**	**8.4%**	**(20,505)**	**46,465**	**5.2%**
6	Rate SGS	1,424,533	453,260	108,864	7.6%	411,624	41,636	(10,409)	41,022	30,613	486,557	6.3%	9.3%	(9,569)	21,044	4.3%
7	Rate LGS	1,218,848	365,930	62,483	5.1%	370,309	(4,379)	1,095	35,099	36,193	399,940	9.0%	7.4%	(10,772)	25,421	6.4%
8	**Rate LT**	**610,603**	**116,240**	**23,192**	**3.8%**	**129,013**	**(12,774)**	**3,193**	**17,583**	**20,777**	**115,650**	**18.0%**	**6.4%**	**(6,222)**	**16,841**	**14.6%**
9	Rate OL	481,036	85,723	21,392	4.4%	91,714	(5,992)	1,498	13,852	15,350	84,837	18.1%	6.9%	(3,912)	11,438	13.5%
10	Rate NL	90.921	13	(4.367)	-4.8%	25	(12)	3	3	5.644	14	40.0%	-0.2%	(3)	3	22.3%
	Rate GL and PL	124,368	28,842	1,557	1.3%	35,574	(6,733)	1,683	3,581	5,265	29,002	18.2%	4.5%	(2,286)	5,265	18.2%
13	Rate TS	5,108	1,662	247	4.8%	1,700	(37)	9	147	156	1,797	8.7%	7.2%	(21)	135	7.5%
14	**Rate I**	**459,301**	**146,157**	**30,722**	**6.7%**	**138,444**	**7,713**	**(1,928)**	**13,226**	**11,298**	**157,318**	**7.2%**	**8.5%**	**(2,941)**	**8,357**	**5.3%**
15	**Rate OPT**	**4,087,483**	**1,311,333**	**163,528**	**4.0%**	**1,386,047**	**(74,714)**	**18,678**	**117,705**	**136,384**	**1,400,366**	**9.7%**	**6.5%**	**(44,757)**	**91,942**	**6.6%**
16	OPTVSecSmall	1,508,720	472,785	65,927	4.4%	493,099	(20,314)	5,079	43,446	48,524	514,218	9.4%	6.8%	(15,559)	32,966	6.4%
17	OPTVSecMed	433,842	141,679	19,927	4.6%	146,256	(4,576)	1,144	12,493	13,637	152,558	8.9%	7.0%	(4,422)	9,215	6.0%
18	OPTVSecLg	479,501	148,598	14,935	3.1%	162,906	(14,308)	3,577	13,808	17,385	160,035	10.9%	5.9%	(4,779)	12,606	7.9%
19	OPTVPriSmall	70,678	17,586	(40)	-0.1%	22,619	(5,034)	1,258	2,035	3,294	18,576	17.7%	3.5%	(698)	2,596	14.0%
20	OPTVPriMed	106,566	35,729	4,814	4.5%	36,958	(1,229)	307	3,069	3,376	38,859	8.7%	6.9%	(1,244)	2,132	5.5%
21	OPTVPriLg	1,335,192	438,989	49,530	3.7%	468,467	(29,478)	7,369	38,449	45,818	460,989	9.9%	6.3%	(15,301)	30,517	6.6%
22	OPTVTransm	152,984	55,966	8,436	5.5%	55,742	224	(56)	4,405	4,349	55,131	7.9%	7.7%	(2,439)	1,910	3.5%
23	**TOTAL RETAIL**	**$ 15,464,742**	**$ 4,569,148**	**$ 835,370**	**5.4%**	**$ 4,569,148**	**$ (0)**	**$ 0**	**$ 445,331**	**$ 445,331**	**$ 4,840,473**	**9.2%**	**7.6%**	**$ (154,573)**	**$ 293,523**	**6.1%**
24	HP		9,640													
25	**TOTAL RETAIL**		**$ 4,578,789**													

Excerpt from "NCJC DR 3-3a DEC-COS-Bund-NC-SCP-No Min Sys-PR with Pirro Exh 4"

DUKE ENERGY CAROLINAS, INC.
Docket No. E-7, Sub 1214
NC RETAIL COST OF SERVICE - PROPOSED - 1CP SUMMER - NO MINIMUM SYSTEM
For the test year ending December 31, 2018
Dollars in Thousands

UNOFFICIAL RATE INCREASE EXHIBIT LINKED TO COS THAT RATE DESGN USES TO PRODUCE PIRRO EXHIBIT 4

THIS IS NOT AN OFFICIAL PIRRO EXHIBIT 4

Calculations for Rate Design in Order to Apply Increase to Unadjusted Billing Determinants

Line No.	Rate Class	Proposed Rate Increase After Reduction in Variance (P)=(I)	Customer Growth Adjustment in Present Revenues (Q)	Weather Normalization Adjustment in Present Revenues (R)	Total Adjustments to Exclude for Rate Design (S)=(Q)+(R)	Ratio of Unadjusted Present Revenues to Adjusted (T)=[(B)-(S)]/(B)	Target Revenue Increase for Rate Design (to be applied to unadjusted billing determinants) (U)=(P)x(T)	Total Unadjusted Present Rates Revenues Including Riders (V)	Proposed Percent Increase to Unadjusted Revenues for Rate Design (W)=(U)/(V)
26	**Rate RS**	**$ 210,066**	**$ 7,853**	**$ (51,916)**	**$ (44,063)**	**102.0%**	**$ 214,320**	**$ 2,326,818**	**9.2%**
27	Rate RS_1	126,736	4,447	(29,401)	(24,954)		129,302	1,357,436	9.5%
28	Rate RT	462	17	(114)	(97)		471	4,309	10.9%
29	Rate RE_1	82,869	3,388	(22,401)	(19,013)		84,547	965,074	8.8%
30	**Rate GS**	**66,806**	**1,776**	**(21,205)**	**(19,429)**	**102.4%**	**68,390**	**907,523**	**7.5%**
31	Rate SGS	30,613	800	(9,975)	(9,175)		31,339	498,097	6.3%
32	Rate LGS	36,193	975	(11,230)	(10,255)		37,052	409,426	9.0%
33	**Rate LT**	**20,777**	**(3,774)**	**-**	**(3,774)**	**103.2%**	**21,451**	**119,405**	**18.0%**
34	Rate OL	15,350	(2,353)	-	(2,353)		15,848	87,591	18.1%
35	Rate NL	6	(2)	-	(2)		6	15	40.0%
36	Rate GL	917	(102)	-	(102)		946	2,932	32.3%
37	Rate PL	4,348	(1,273)	-	(1,273)		4,489	27,011	16.6%
38	Rate TS	156	(44)	-	(44)		162	1,855	8.7%
39	**Rate I**	**11,298**	**241**	**(970)**	**(729)**	**100.5%**	**11,354**	**158,102**	**7.2%**
40	**Rate OPT**	**136,384**	**3,847**	**(35,475)**	**(31,628)**	**102.4%**	**139,636**	**1,434,098**	**9.7%**
41	OPTVSecSmall	48,524	1,386	(14,964)	(13,578)	102.9%	49,918	528,986	9.4%
42	OPTVSecMed	13,637	373	(3,048)	(2,675)	101.9%	13,895	155,439	8.9%
43	OPTVSecLg	17,385	392	(2,678)	(2,286)	101.5%	17,652	162,497	10.9%
44	OPTVPriSmall	3,294	79	(594)	(515)	102.9%	3,390	19,120	17.7%
45	OPTVPriMed	3,376	108	(1,027)	(919)	102.6%	3,463	39,858	8.7%
46	OPTVPriLg	45,818	1,294	(10,464)	(9,170)	102.1%	46,775	470,619	9.9%
47	OPTVTransm	4,349	216	(2,701)	(2,485)	104.4%	4,542	57,579	7.9%
48	**TOTAL RETAIL**	**$ 445,331**	**$ 9,942**	**$ (109,566)**	**$ (99,624)**	**102.2%**	**$ 455,152**	**$ 4,945,947**	**9.2%**

CAC
IURC Cause No. 45253
Data Request Set No. 12
Received: September 23, 2019

CAC 12.4

Request:

Please reference Diaz Revised Direct, p. 30, ll. 4-19.

a) Please confirm that all production plant costs are classified as demand-related in the retail cost of service study.

b) Please indicate whether secondary pole, conductor, and transformer plant costs are classified in the retail cost of service study as facility-related or connection-related.

c) Please indicate whether secondary pole, conductor, and transformer costs are allocated based on number of customers, diversified class demand, or non-coincident peak demand.

d) For those instances where a secondary transformer serves more than one customer, does the Company size the transformer to serve the expected diversified load on the transformer or the expected sum of the individual customer maximum loads on the transformer? Please explain.

e) Please provide copies of any planning documents or engineering design guidelines which describe Company practice with regard to sizing of secondary transformers.

Response:

a) Yes, all production plant as categorized in the FERC Electric Plant Chart of Accounts in the Uniform System of Accounts is classified as demand related in the retail cost of service study.

b) Secondary pole, secondary conductor, and secondary transformer plant costs are are included in Total Connection Charges. Also included in Total Connection Charges are "fixed connection charges", "services", "secondary line transformers", and "secondary lines". In Diaz Revised Direct p. 30, lines 16-17, Diaz states that "connection-related charges include electric meters and customer accounts"; in this context, Witness Diaz is referring to the "fixed connection charge" component only. The fixed connection charges, as used by rate design to develop the customer charge, do <u>not</u> include secondary pole, secondary conductor, and secondary transformer plant costs in the customer charge.

c) These costs were allocated to retail customers based on Non-coincident peak demand allocators.

d) We use a diversified load on calculation, built into our Secondary Electrical Design System (SEDS) software, when sizing transformers that serve more than one customer.

e) Transformers serving residential load/customers are sized based on diversified load according to coincidence factors and total numbers of customers per transformer. The diversified load shall not exceed our transformer loading guidelines. However, total connected load can't exceed the cold load pick up guidelines (loss of diversity). Also, flicker needs to be evaluated based on guideline below (not to exceed 4.2%).

Taken from a section of the job aid for SEDS:

Residential Transformer Loading Summary

Maximum Transformer Loading

	Summer	Winter
Carolinas	140%	170%
Midwest	145%	185%

Power Factor - 95%

Locked Rotor Amps

Tonnage	1.5	2	2.5	3	3.5	4	5
	48	63	77	93	112	137	160

Maximum Allowable Flicker – 4.2%

Cold Load (loss of diversity) - Summer – 225%, Winter – 270%

Air Conditioner

Ton	AC	Range/Oven	Misc Load	Total Load (KW)
1.5	1.9	3.0	1.5	6.6
2	2.6	3.0	1.5	7.3
2.5	3.2	3.0	1.5	8.0
3	3.9	3.0	1.5	8.7
3.5	4.5	3.0	1.5	9.4
4	5.2	3.0	2.0	10.6
5	6.5	3.0	2.5	12.5

Heat Pump

Ton	H.P.	Strip	Wtr Htr	Misc Load	Total Load (KW)
1.5	1.9	5	4.5	1.5	13.1
2	2.6	10	4.5	1.5	18.8
2.5	3.2	10	4.5	1.5	19.5
3	3.9	10	4.5	1.5	20.2
3.5	4.5	10	4.5	1.5	20.9
4	5.2	15	4.5	2.0	27.1
5	6.5	15	4.5	2.5	29.0

Assumed load per ton (A/C or Heat Pump) – 1.4KW

Diversity (Coincidence Factor)

Carolinas

Customers	Heat Pump	A/C
1	1	1
2	.695	.82
3	.568	.73
4	.486	.645
5	.427	.58
6	.377	.515
7	.352	.49
8	.337	.475
9	.323	.47
10	.314	.46
11	.314	.46
12 & up	.314	.46

Midwest

Customers	Heat Pump or A/C
1	1
2	.8
3	.6
4	.5
5	.45
6 & up	.4

Witness: Diaz for a-c, Abbott/Hart for d-e.

Duke Energy Carolinas
Response to
NCJC Data Request
Data Request No. 3

Docket No. E-7, Sub 1214

Date of Request: January 10, 2020
Date of Response: January 20, 2020

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X	**NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC Data Request No. 3-2, was provided to me by the following individual(s): Kaari K. Beard, Rates & Regulatory Manager, Rate Case Planning & Execution, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

3-2. Reference the response to NCUC Form E-1 Data Request, Item No. 45(c).
a) Please provide in electronic spreadsheets with all cell formulas and file linkages intact versions of the COSS and Allocators reports for the 1CP Summer scenario based on a cost of service study which:
i) Classifies 100% of the costs recorded in FERC Accounts 364 through 368 as demand-related (i.e., does not classify any distribution plant costs as customer-related based on a minimum system analysis.)
ii) Allocates demand-related distribution costs based on rate class diversified peak demand (i.e., peak demand for the class as a whole) rather than class non-coincident peak demand (i.e., the sum of individual

Response:

In response to a) i) As part of the Company's response to NCUC PS Data Request 100-18, please see file 'NCUC PS DR 100-18 DEC-COS-Bund-NC-SCP-No Min Sys-PR_12 ME 2018_R1' for the Summer 1CP Cost of Service – No Minimum System proposed version.
In response to a) ii) The Company does not have this data available.

From:	Robinson, Camal O.
To:	Tirrill Moore; Somers, Bo
Cc:	David Neal; Smith, MoNiqueka L.; Jagannathan, Molly McIntosh
Subject:	RE: DEC Response to NCJC DR 3-2, Docket No. E-7, Sub 1214
Date:	Tuesday, February 04, 2020 5:43:45 PM
Attachments:	image001.png

Hi Tirrill:

We reviewed the request. This information is not readily available. For the Company to allocate demand-related distribution costs on rate class diversified peak demand, we would need to run a cost of service using different statistical data and flow that through and unfortunately that is not easily done and would require original work. Thanks.

Camal O. Robinson
Associate General Counsel
Duke Energy | 550 South Tryon Street | Charlotte, NC 28202
Office: (980) 373-2631 | Cell: (978) 435-5131
E-mail address: camal.robinson@duke-energy.com

DUKE ENERGY

From: Tirrill Moore <tmoore@selcnc.org>
Sent: Monday, February 3, 2020 2:09 PM
To: Robinson, Camal O. <Camal.Robinson@duke-energy.com>; Somers, Bo <Bo.Somers@duke-energy.com>
Cc: David Neal <dneal@selcnc.org>; Smith, MoNiqueka L. <MoNiqueka.Smith@duke-energy.com>
Subject: DEC Response to NCJC DR 3-2, Docket No. E-7, Sub 1214

Dear Counsel,

In NCJC DR 3-2(a)(ii), the Company was asked to "provide in electronic spreadsheets with all cell formulas and file linkages intact versions of the COSS and Allocators reports for the 1CP Summer scenario based on a cost of service study" that allocates "demand-related distribution costs based on rate class diversified peak demand." The Company's response to NCJC DR 3-2(a)(ii) stated "The Company does not have this data available." This same request was made under NCJC DR 3-1(a)(ii) and the Company gave the same response.

However, in response to PS DR 100-9, the Company acknowledged that is does have the data necessary to run a COSS that allocates demand-related distribution costs based on rate class diversified peak demand. The attached spreadsheet, produced in response to PS DR 100-9, shows the Company's estimate of hourly demand in 2018 for each NC retail customer class. The diversified (i.e. class) peak demand is simply the maximum of the hourly demands. The load research data the Company used to generate the hourly demands for each customer class presumably could also be used to generate hourly demands for each rate class.

We also noted that a portion of data request NCJC DR 3-2(a)(ii) was inadvertently cut off. To be sure that the above inconsistency did not occur as a result, NCJC DR 3-2 should read as follows:

"3-2. Reference the response to NCUC Form E-1 Data Request, Item No. 45(c).

> (a) Please provide in electronic spreadsheets with all cell formulas and file linkages intact versions of the COSS and Allocators reports for the 1CP Summer scenario based on a cost of service study which:
>
> > (ii) Allocates demand-related distribution costs based on rate class diversified peak demand (i.e., peak demand for the class as a whole) rather than class non-coincident peak demand (i.e., the sum of individual customers' maximum demand)."

-

We request that you respond to this revised request in light of the fact that the Company's previous response was inaccurate. If your answer is the same, we would like an explanation of this apparent contradiction.

Thank you,

Tirrill Moore
Associate Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516-2356
T: (919) 967-1450 | F: (919) 929-9421
http://www.southernenvironment.org

Duke Energy Carolinas
Response to
North Carolina Public Staff Data Request
Data Request No. NCPS 100

Docket No. E-7, Sub 1214

Date of Request:	**November 26, 2019**
Date of Response:	**January 17, 2020**

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The attached Revised response to North Carolina Public Staff Data Request No. 100-18, was provided to me by the following individual(s): Kaari K. Beard, Rates & Regulatory Strategy Manager, and was provided to North Carolina Public Staff under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 100
DEC Docket No. E-7, Sub 1214
Item No. 100-18

<u>Request:</u>

18. Please provide a calculation for the "minimum intercept method" and the "basic customer method" of apportioning distribution system costs as customer or demand-related. The Company's response should be accompanied by workpapers showing the calculations. The Company's response may refer to information or workpapers provided to the Public Staff in response to the Public Staff's report filed March 28, 2019 in Docket No. E-100, Sub 162.

<u>Revised Response 1/17/2020:</u>

- Please see the two revised attached files "NCUC PS DR 100-18 DEC-COS-Bund-NC-SCP-No Min Sys-PR_12 ME 2018_R1." and "NCUC PS DR 100-18 DEC-COS-Unb-NC-SCP-No Min Sys-PR_12 ME 2018_R1". The Company needed to correct two customer class allocation factor assignments in the proposed run versions. The 'CASH WORKING CAPITAL-PER BOOK' cost of service line description should have been allocated using All - Rate Base x CWC instead of All – Cust Num. The 'PF O&M-Normalize for weather-Uncollectibles' cost of service line description should have been allocated using All – Cust Num instead of All – Rate Base x CWC.

NCUC PS DR 100-18 DEC-COS-Unb-NC-S

NCUC PS DR 100-18 DEC-COS-Bund-NC-

DUKE ENERGY CAROLINAS, LLC
Docket No. E-7, Sub 1214
DEMAND, ENERGY AND CUSTOMER COS STUDY
For the test year ending December 31, 2018
NC RETAIL COST OF SERVICE - PROPOSED - 1CP SUMMER - NO MINIMUM SYSTEM
Summer CP

	Demand	UNIT	COSTS	Energy	UNIT	COSTS	DEMAND & ENERGY	UNIT	COSTS	CUSTOMER	UNIT	COSTS
	Revenue	KW [1]	$/KW/Mo	Revenue	Annual KWH [2]	Cents/KWH	Revenue	Annual KWH [2]	Cents/KWH	Revenue	Avg Bills [3]	$/Cust/Mo
RS1	$ 946,403,123	3,484,971	22.63	$ 340,228,761	12,890,984,000	2.64	$ 1,286,631,884	12,890,984,000	9.98	$ 141,007,490	1,023,072	11.49
RT	2,953,005	11,055	22.26	1,332,682	49,940,000	2.67	4,285,686	49,940,000	8.58	261,653	1,956	11.15
RE	639,419,581	1,923,976	27.70	262,031,959	9,822,106,000	2.67	901,451,540	9,822,106,000	9.18	103,214,171	731,513	11.76
TOTAL RS	**1,588,775,708**	**5,420,002**	**24.43**	**603,593,402**	**22,763,030,000**	**2.65**	**2,192,369,110**	**22,763,030,000**	**9.63**	**244,483,314**	**1,756,541**	**11.60**
SGS	331,000,889	1,173,097	23.51	128,996,812	4,567,331,000	2.82	459,997,701	4,567,331,000	10.07	33,878,821	242,917	11.62
LGS	264,670,288	1,094,460	20.15	146,581,878	5,142,000,000	2.85	411,252,166	5,142,000,000	8.00	1,340,374	9,171	12.18
TOTAL GS	**595,671,177**	**2,267,557**	**21.89**	**275,578,690**	**9,709,331,000**	**2.84**	**871,249,867**	**9,709,331,000**	**8.97**	**35,219,195**	**252,088**	**11.64**
OL	31,163,698	-	-	11,990,677	430,090,000	2.79	43,154,375	430,090,000	10.03	61,544,474	277,388	18.49
NL	12,251	-	-	7,867	275,000	2.86	20,118	275,000	7.32	445	7	5.29
GL	3,307,350	-	-	501,474	18,710,000	2.68	3,808,824	18,710,000	20.36	86,946	1,446	5.01
PL	24,806,818	-	-	6,510,271	232,673,000	2.80	31,317,089	232,673,000	13.46	401,987	6,284	5.33
GL and PL	28,114,168	-	-	7,011,745	251,383,000	2.79	35,125,913	251,383,000	13.97	488,933	7,730	5.27
OL_GL_PL	**59,290,117**	**-**	**-**	**19,010,289**	**681,748,000**	**2.79**	**78,300,406**	**681,748,000**	**11.49**	**62,033,851**	**285,125**	**18.13**
TS	990,093	1,270	64.97	252,751	10,081,000	2.51	1,242,843	10,081,000	12.33	644,122	5,914	9.08
TOTAL LIGHTING	**60,280,210**	**1,270**	-	**19,263,040**	**691,829,000**	2.78	**79,543,250**	**691,829,000**	11.50	**62,677,973**	**291,039**	17.95
I	100,041,760	365,855	**22.79**	57,438,357	2,048,172,000	**2.80**	157,480,117	2,048,172,000	**7.69**	524,421	3,707	**11.79**
OPTSecSmall	313,788,027	1,379,023	18.96	219,419,039	7,756,595,000	2.83	533,207,066	7,756,595,000	6.87	2,291,026	16,685	11.44
OPTSecMed	87,900,801	385,392	19.01	70,034,487	2,500,753,000	2.80	157,935,288	2,500,753,000	6.32	74,657	289	21.53
OPTSecLg	88,981,423	430,962	17.21	79,255,986	2,874,503,000	2.76	168,237,409	2,874,503,000	5.85	34,080	79	35.95
OPTPriSmall	10,689,306	66,221	13.45	10,746,531	392,631,000	2.74	21,435,837	392,631,000	5.46	15,722	123	10.65
OPTPriMed	21,498,657	98,691	18.15	18,538,654	661,550,000	2.80	40,037,310	661,550,000	6.05	13,869	66	17.51
OPTPriLg	249,354,913	1,230,871	16.88	244,798,046	8,845,687,000	2.77	494,152,959	8,845,687,000	5.59	38,754	136	23.75
OPTTransLg	27,940,526	148,149	15.72	34,974,669	1,236,620,000	2.83	62,915,195	1,236,620,000	5.09	(9,927)	4	(206.81)
OPT	**800,153,653**	**3,739,309**	17.83	**677,767,412**	**24,268,339,000**	2.79	**1,477,921,065**	**24,268,339,000**	6.09	**2,458,181**	**17,382**	11.79
TOTAL RETAIL	**$ 3,144,922,508**	**11,793,993**	**22.22**	**$ 1,633,640,901**	**59,480,701,000**	**2.75**	**$ 4,778,563,409**	**59,480,701,000**	**8.03**	**$ 345,363,083**	**2,320,757**	**12.40**
	-			-			-			-		

[1] Allocation Factor: All - Production Demand
[2] Allocation Factor: All - MWHs at Meter
[3] Allocation Factor: All - Cust Num

Works Cited

Acton, Jan, Bridger Mitchell, and Ragnhill Mowill. 1976. "Residential Demand for Electricity in Los Angeles: An Econometric Study of Disaggregate Data" Rand Report R-1899-NSF, Rand Corporation: Santa Monica, Cal., 1976. www.prgs.edu/content/dam/rand/pubs/reports/2008/R1899.pdf.

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Duke Energy Carolinas
Response to
NCJC Data Request
Data Request No. 1

Docket No. E-7, Sub 1214

Date of Request: December 19, 2019
Date of Response: January 13, 2019

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The attached supplemental response to NCJC Data Request No. 1-4, was provided to me by the following individual(s): Phillip O. Stillman, Director, Load Forecast and Fundamentals, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

1-4. Reference the response to NCUC Form E-1 Data Request, Item No. 43.
a) Please provide an electronic spreadsheet version of the Table 3-A: Load Forecast with Energy Efficiency Programs showing the forecast of summer MW peak demand, winter MW peak demand, and annual MWh sales solely for the residential class.
b) Please provide an electronic spreadsheet version of the Table C-7: Load Forecast with Energy Efficiency Programs and Before Demand Reduction Programs showing the forecast of summer MW peak demand, winter MW peak demand, and annual MWh sales solely for the residential class.
c) Please provide an electronic spreadsheet version of the table “Projected MWh Impacts of EE Programs: Base Case” showing annual MWh load reductions solely for residential EE programs.

Supplemental Response January 13, 2020:

See attached file "NCJC 1-4 - Annual MWH Res Sales UEE.xlsx", which provides the information out of the Company's most recently filed 2019 IRP:
1) Residential sales before UEE
2) UEE
3) Residential sales after UEE

DEC NCJC 1-4 -
Annual MWH Res Sa

DEC NCJC 1-4: Annual Residential Sales (MWHs) - Before Impacts, UEE Impacts, After Impacts

Year	Residential Sales Before UEE	UEE Impacts	Residential Sales After UEE
2020	30,426,062	(217,655)	30,208,407
2021	30,677,483	(309,106)	30,368,377
2022	31,063,336	(385,356)	30,677,980
2023	31,460,391	(453,128)	31,007,263
2024	31,842,076	(516,617)	31,325,459
2025	32,146,109	(582,219)	31,563,890
2026	32,522,833	(652,354)	31,870,479
2027	32,927,633	(723,665)	32,203,968
2028	33,384,968	(789,891)	32,595,077
2029	33,801,270	(848,143)	32,953,127
2030	34,269,541	(909,307)	33,360,233
2031	34,777,816	(927,887)	33,849,929
2032	35,328,867	(928,817)	34,400,050
2033	35,845,326	(951,888)	34,893,437
2034	36,463,106	(971,948)	35,491,158

Found in Box 27

(?)

EXHIBIT JFW-9

Sharon L. Nelson, Chairman
Richard D. Casad, Commissioner
A. J. "Bud" Pardini, Commissioner

STATE OF WASHINGTON

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

P.O. Box 9022 • 1300 S. Evergreen Park Dr. S.W. • Olympia, Washington 98504-9022 • (206) 753-6423 • (SCAN) 234-6423

REF:6-1132

June 11, 1992

Mr. Julian Ajello
California PUC
505 Van Ness Avenue
San Francisco, California 94102

Dear Mr. Ajello:

Please accept this belated response to your request for review of the February, 1991 draft of the new NARUC Electric Utility Cost Allocation Manual. Our staff recognizes that the final has now been printed. However, the inconsistent treatment of customer related costs in the manual is of concern. In three areas, three different approaches are presented. The first is an energy weighted approach, the second the so-called "minimum-system" or "zero-intercept" method, and the last is the "basic customer" method.

At page 39 of the draft, distribution plant is identified as being customer, demand, and energy-related. That is consistent with the treatment of gas distribution plant by this Commission, where it has ordered that 50% of distribution mains be treated as commodity-related. Our Commission has not made specific findings on electric distribution plant, except as set forth below.

At pages 91-100 of the draft, the minimum-system and zero intercept methods are presented. These methods do not conform to the matrix on page 39, which incorporates an energy component of distribution plant. Unfortunately, these two methods are the only methods presented. These are the two methods our Commission has explicitly rejected.

Finally, at page 148, in the section on marginal cost determination, the "basic customer" method, counting as customer related costs only meters, services, meter reading, and billing, is identified and defended.

Previous drafts included additional methods which are missing from the final version. For example, the 10/31/88 draft discussed at the fall meeting in San Francisco contained a section explicitly setting forth the basic customer method in the embedded cost section. In November of 1988, a section discussing the energy-weighted method was distributed to the Committee.

Our Commission has been extremely clear about one thing in this area: that the "minimum-distribution" and "minimum-intercept" methods are not acceptable, and that the only costs which should be considered customer-related are the costs of meters, services, meter reading and billing. Our staff believes that is the most common approach taken by Commissions around the country. For example, in Iowa, the administrative rules of the Commission set this forth explicitly, while in Arizona and Illinois, the Commissions have explicitly rejected the minimum-system or minimum-intercept methods in favor of the basic customer approach.

In gas cost of service, our Commission has explicitly found that distribution plant (including service connections) is partially demand-related and partially commodity related, consistent with the matrix on page 39. The corresponding plant on the electric side -- poles, conductors and transformers -- has not been positively resolved in any cases to date. A recently filed electric cost of service case will provide an opportunity for advocates of the demand-only allocation approach and those favoring an energy weighing approach to make their cases before the Commission.

We hope that it is possible to either correct future editions of the Manual to reflect the variety of approaches to determining customer-related costs, or to even issue a correction to this edition.

Please feel free to contact Bruce Folsom at (206) 586-1132 with any questions you may have.

Sincerely,

Paul Curl

Paul Curl
Secretary