Frank Lacey

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Summary

Recognized energy industry executive and leader known for implementing innovative regulatory and business strategies empowering clients to benefit from emerging policies. Successful in achieving business growth and value through regulatory strategy.

Experience

Board of Directors
Advanced Energy Management Alliance (Founding member and Chairman); Formerly served: Smart Electric Power Alliance (f/k/a Solar Electric Power Association) (finance committee); Association for Demand Response and Smart Grid (finance chair); Electric Power Supply Association (finance committee); ERCOT (finance committee); Retail Energy Supply Association.

Electric Advisors Consulting, LLC 2015- Present
Founder and President

Advise senior leadership on utilizing analytics to develop strategies to address legislative and regulatory change in the energy industry. Also advise and assist entities on facilitating legislative and regulatory change to accommodate evolving business strategies and technologies. Active participation in rate cases and other regulatory initiatives focused on correcting cost allocations and other biases embedded in partially restructured energy markets.

Comverge, Inc./CPower Corporation 2011- 2015
Senior Vice President, Regulatory and Market Strategy

Develop and implement corporate regulatory strategy, including new market entry plans for a $150 million company performing demand response services in the electricity markets.

Direct Energy 2006 - 2011
Director, Products and Complex Transactions (2008-2011)

For a multi-billion dollar retail electric and gas company, managed Complex Transaction team consisting of four direct reports and eight functional leaders from across the organization, facilitating development of over $50 million in incremental gross margin sold, while operating within risk management framework.

Director, Government and Regulatory Affairs (2006-2008)

Managed regulatory strategy and regulatory risk in Mid-Atlantic region of US, participating in multiple rate proceedings and regulatory initiatives, securing approximately $100 million in value.

Starlight Energy 2004 - 2006
President

Led the development of business plan and pro formas for venture seeking $20 million in equity financing and other financial relationships. Successes included securing $100 million credit relationship and working capital financing to enable launch of retail Electricity Company.

Strategic Energy 2001- 2004
Director, Regulatory Affairs,

Served on the company's Leadership team, managing a regulatory group of 15 people, leading the development of regulatory strategy, the oversight of regulatory risk and the attainment of desired regulatory results, advocating across 13 states and at FERC.

Arthur Andersen 1998 - 2001
Senior Manager
Responsibility for development and growth of Andersen's transmission restructuring business in Eastern half of US market.

Putnam, Hayes and Bartlett, Inc 1995 - 1998
Associate Consultant
Associate consultant in firm's energy practice with expertise in environmental asset valuation.

Education

Carnegie Mellon University, Tepper School of Business
MSIA (MBA) with concentrations in finance, entrepreneurship and environmental management
Self-designed major with supplemental coursework taken in Public Policy and Engineering Schools.

- Entrepreneur of the Year Award, Don Jones Center for Entrepreneurship.
- Thomas M. Kerr Ethics in Business Award.

University of Maryland
B.S. in Transportation and Logistics

Programs for Life
Certified Leadership Development Trainer

Prepared Direct Testimony of Frank Lacey On Behalf of Strategic Energy, LLC, before the Public Utilities Commission of the State of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. June 6, 2002.

Prepared Rebuttal Testimony of Frank Lacey On Behalf of Strategic Energy, LLC before the Public Utilities Commission of the State of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. June 20, 2002

Cross Examination testimony of On Behalf of Strategic Energy, LLC before the Public Utilities Commission of the State of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. July 2002.

Prepared Testimony of Frank Lacey on the subject of truing up the CERS Fee On Behalf of Strategic Energy, LLC before the Public Utilities Commission Of the State Of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. March 19, 2003

Prepared Direct Testimony of Frank Lacey on behalf of Strategic Energy L.L.C. before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company*, Docket Nos. R-00038092, R-00038092C0001 and R-00038092C0002. January 2003.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Strategic Energy L.L. C. Before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company* Docket Nos. R-00038092, R-00038092C0001 and R-00038092C0002. February 2003.

Prepared Supplemental Testimony of Frank Lacey on behalf of Strategic Energy L.L.C. before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company* Docket Nos. R-00038092, R-00038092C0001, R-00038092C0002. November 2003

Cross Examination testimony of Frank Lacey on behalf of Strategic Energy L.L.C. before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company* Docket Nos. R-00038092, R-00038092C0001, R-00038092C0002. July 1, 2003.

Prepared Direct Testimony of Frank Lacey submitted on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the *Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company* Case No. 02-2779-EL-ATA and the *Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code* Case No. 02-2879-EL-AAM. May 19, 2003.

Prepared Supplemental Testimony of Frank Lacey submitted on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the *Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company* Case No. 02-2779-EL-ATA and the *Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code* Case No. 02-2879-EL-AAM. June 12, 2003.

Deposition Testimony of Frank Lacey submitted on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the *Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company* Case No. 02-2779-EL-ATA and the *Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code* Case No. 02-2879-EL-AAM. May 2003 and June 2003.

Cross Examination testimony of Frank Lacey on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the *Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company* Case No. 02-2779-EL-ATA and the *Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code* Case No. 02-2879-EL-AAM. June 2003.

Oral Testimony of Frank Lacey before the Standing Committee on Energy of the New York State Assembly on the issue of Ensuring a Reliable Supply of Electricity to the People of New York, Chairman Paul D Tonko, presiding. March 6, 2003

Prepared Direct Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. before the Pennsylvania Public Utility Commission in the matter of the *Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service.* Docket No. P-00032071. February 2004.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. before the Pennsylvania Public Utility Commission in the matter of the *Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service.* Docket No. P-00032071. February 2004.

Cross Examination testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. before the Pennsylvania Public Utility Commission in the matter of the *Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service.* Docket No. P-00032071. April 1, 2004.

Oral Testimony of Frank Lacey at the *POLR Roundtable* before the Pennsylvania Public Utility Commission re: Optimal Future POLR Design models. May 3, 2004.

Prepared Direct Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. and Mid-American Energy Company before the Public Utilities Commission of Ohio in the matters of *The Application of the Cincinnati Gas & Electric Company to Modify its Non-Residential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish a Pilot Alternative Competitively-Bid Service Rate Option Subsequent to Market Development Period*, Case No. 03-93-EL-ATA, *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with the Midwest ISO*, Case No. 03-2079-EL-AAM, and *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital investment in its Electric Transmission and Distribution System and to Establish a Capital Investment Reliability Rider to be Effective After the Market Development Period*, Case Nos. 03-2080-EL-AAM and 03-2080-EL-ATA. May 6, 2003.

Deposition of Frank Lacey in the matters of *The Application of the Cincinnati Gas & Electric Company to Modify its Non-Residential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish a Pilot Alternative Competitively-Bid Service Rate Option Subsequent to Market Development Period*, Case No. 03-93-EL-ATA, *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with the Midwest ISO*, Case No. 03-2079-EL-AAM, and *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital investment in its Electric Transmission and Distribution System and to Establish a Capital Investment Reliability Rider to be Effective After the Market Development Period*, Case Nos. 03-2080-EL-AAM and 03-2080-EL-ATA. May 2003.

Cross Examination Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. and Mid-American Energy Company before the Public Utilities Commission of Ohio in the matters of *The Application of the Cincinnati Gas & Electric Company to Modify its Non-Residential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish a Pilot Alternative Competitively-Bid Service Rate Option Subsequent to Market Development Period*, Case No. 03-93-EL-ATA, *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with the Midwest ISO*, Case

No. 03-2079-EL-AAM, and *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital investment in its Electric Transmission and Distribution System and to Establish a Capital Investment Reliability Rider to be Effective After the Market Development Period*, Case Nos. 03-2080-EL-AAM and 03-2080-EL-ATA. May 18, 2003.

Oral Testimony of Frank Lacey before the Michigan Senate Committee on Technology and Energy on the subject of revision to Public Act 141, the Michigan Electricity Choice and Restructuring Act, Chairman Bruce Patterson, Presiding. May 19, 2004.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Maryland Senate Finance Committee on Senate Bill 561 on the subject of communications between electric companies and suppliers to enhance the development of competitive electric markets, Chairman Thomas Middleton, Presiding. March 7, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Maryland Senate Finance Committee on Senate Bills 814, 1048, 1051 and 1078 on the subject of retail electricity market design, Chairman Thomas Middleton, Presiding. March 14, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Maryland House of Delegates Economic Matters Committee on House Bills 1334, 1654 and 1712 on the subject of retail electricity market design, Chairman Dereck Davis, Presiding. March 14, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utility Commission in the Matter of *Petition of Direct Energy Services, LLC for Emergency Order*, Docket No. P-00062205, April 11, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utility Commission in the Matter of *Policies to Mitigate Potential Electricity Price Increases*, Docket No. M-00061957, June 22, 2006.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Duquesne Light Company Base Rate Case*, Docket No. R-00061346, July 7, 2006. (Case Settled)

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Duquesne Light Company Base Rate Case*, Docket No. R-00061346, August 2, 2006. (Case Settled)

Prepared Surrebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Duquesne Light Company Base Rate Case*, Docket No. R-00061346, August 16, 2006. (Case Settled)

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of PPL Electric Utilities Corporation for Approval of Competitive Bridge Plan*, Docket No. P-00062227, November 15, 2006.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of PPL Electric Utilities Corporation for Approval of Competitive Bridge Plan*, Docket No. P-00062227, December 6, 2006.

Prepared Surrebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of PPL Electric Utilities Corporation for Approval of Competitive Bridge Plan*, Docket No. P-00062227, December 15, 2006.

Oral Rejoinder Testimony and Cross-examination of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of PPL Electric Utilities Corporation for Approval of Competitive Bridge Plan*, Docket No. P-00062227, December 15, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania House of Representatives, Consumer Affairs Committee, Honorable Joseph Preston Jr., Chairman, March 15, 2007.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Duquesne Light Company for Approval of Default Service Plan for the Period January 1, 2008 through December 31, 2010*, Docket No. P-00072247, March 29, 2007. (case settled)

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Duquesne Light Company for Approval of Default Service Plan for the Period January 1, 2008 through December 31, 2010*, Docket No. P-00072247, April 12, 2007. (case settled)

Prepared Surrebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Duquesne Light Company for Approval of Default Service Plan for the Period January 1, 2008 through December 31, 2010*, Docket No. P-00072247, April 20, 2007. (case settled)

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Pike County Light & Power Company for Expedited Approval of its Default Service Implementation Plan, Docket No.* P-00072245, March 28, 2007.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Pike County Light & Power Company for Expedited Approval of its Default Service Implementation Plan, Docket No.* P-00072245, April 11, 2007.

Oral Surrebuttal Testimony and Cross-examination Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Pike County Light & Power Company for Expedited Approval of its Default Service Implementation Plan, Docket No.* P-00072245, April 19, 2007.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC, before the Maryland Public Service Commission *In the Matter of the Commission's Investigation of Investor-owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, Case No. 9117, September 14, 2007.

Prepared Reply Testimony of Frank Lacey on behalf of Direct Energy Services, LLC, before the Maryland Public Service Commission *In the Matter of the Commission's Investigation of Investor-owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, Case No. 9117, September 28, 2007.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC, before the Maryland Public Service Commission *In the Matter of the Commission's Investigation of Investor-owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, Case No. 9117, October 2007.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania House of Representatives Republican Policy Committee, Honorable Michael Turzai, Chairman, March 17, 2008.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of *Petition of West Penn Power Company dba Allegheny Power for Approval of its Retail Electric Default Service Program and Competitive Procurement Plan for Service at the Conclusion of the Restructuring Transition Period, Docket No.* P-00072342, February 12, 2008.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of *Petition of West Penn Power Company dba Allegheny Power for Approval of its Retail Electric Default Service Program and Competitive Procurement Plan for Service at the Conclusion of the Restructuring Transition Period, Docket No.* P-00072342, March 11, 2008.

Prepared Surrebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of *Petition of West Penn Power Company dba Allegheny Power for Approval of its Retail Electric Default Service Program and Competitive Procurement Plan for Service at the Conclusion of the Restructuring Transition Period, Docket No.* P-00072342, March 25, 2008.

Oral Cross-examination Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of *Petition of West Penn Power Company dba Allegheny Power for Approval of its Retail Electric Default Service Program and Competitive Procurement Plan for Service at the Conclusion of the Restructuring Transition Period, Docket No.* P-00072342, April 2, 2008.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC, before the Pennsylvania Public Utility Commission in the matter of the *Joint Application of West Penn Power Company d/b/a Allegheny Power, Trans-Allegheny Interstate Line Company and FirstEnergy Corp. for a Certificate of Public Convenience under Section 1102(a)(3) of the Public Utility Code approving a change of control of West Penn Power Company And Trans-Allegheny Interstate Line Company,* Docket Nos. A-2010-2176520 and A-2010-2176732, August 17, 2010

Prepared Sur-Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC, before the Pennsylvania Public Utility Commission in the matter of the *Joint Application of West Penn Power Company d/b/a Allegheny Power, Trans-Allegheny Interstate Line Company and FirstEnergy Corp. for a Certificate of Public Convenience under Section 1102(a)(3) of the Public Utility Code approving a change of control of West Penn Power Company And Trans-Allegheny Interstate Line Company,* Docket Nos. A-2010-2176520 and A-2010-2176732, October 1, 2010.

Oral Cross-examination Testimony of Frank Lacey on behalf of Direct Energy Services, LLC, before the Pennsylvania Public Utility Commission in the matter of the *Joint Application of West Penn Power Company d/b/a Allegheny Power, Trans-Allegheny Interstate Line Company and FirstEnergy Corp. for a Certificate of Public Convenience under Section 1102(a)(3) of the Public Utility Code* *approving a change of control of West Penn Power Company And Trans-Allegheny Interstate Line Company,* Docket Nos. A-2010-2176520 and A-2010-2176732, October 5, 2010.

Oral Testimony of Frank Lacey on behalf of Comverge, Inc. at FERC Technical Conference in the Matter of *PJM Interconnection, L.L.C.*, Docket No. ER11-3322-000, July 29, 2011, discussing the topic of appropriate methodologies to estimate load reductions during a demand response curtailment event.

Prepared Direct Testimony of Frank Lacey on behalf of Comverge, Inc., before the Illinois Commerce Commission in the matter of *Commonwealth Edison Company Petition for Statutory Approval of Smart Grid Advanced Metering Infrastructure Deployment Plan Pursuant to Section 16-108.6 of the Public Utilities Act*, Docket No. 12-0298, May 11, 2012.

Oral Cross-examination Testimony of Frank Lacey on behalf of Comverge, Inc., before the Illinois Commerce Commission in the matter of *Commonwealth Edison Company Petition for Statutory Approval of Smart Grid Advanced Metering Infrastructure Deployment Plan Pursuant to Section 16-108.6 of the Public Utilities Act*, Docket No. 12-0298, May 23, 2012.

Prepared Direct Testimony of Frank Lacey On Behalf of Comverge, Inc., before the Illinois Commerce Commission in the matter of *Ameren Illinois Company Petition for Statutory Approval of a Smart Grid Advanced Metering Infrastructure Deployment Plan Pursuant to Section 16-108.6 of the Public Utilities Act*, Docket No. 12-0244 on rehearing, August 24, 2012.

Oral Cross-examination Testimony of Frank Lacey On Behalf of Comverge, Inc., before the Illinois Commerce Commission in the matter of *Ameren Illinois Company Petition for Statutory Approval of a Smart Grid Advanced Metering Infrastructure Deployment Plan Pursuant to Section 16-108.6 of the Public Utilities Act*, Docket No. 12-0244 on rehearing, September 20, 2012.

Prepared Direct Testimony of Frank Lacey on Behalf of Comverge, Inc., before the Illinois Commerce Commission in the matter of *Commonwealth Edison Company's Petition for Approval of Tariffs Implementing ComEd's Proposed Peak Time Rebate Program*, Docket No. 12-0484, October 25, 2012.

Oral Cross-examination Testimony of Frank Lacey on Behalf of Comverge, Inc., before the Illinois Commerce Commission in the matter of *Commonwealth Edison Company's Petition for Approval of Tariffs Implementing ComEd's Proposed Peak Time Rebate Program*, Docket No. 12-0484, December 7, 2012.

Prepared Direct Testimony of Frank Lacey on Behalf of Comverge, Inc., before the Maryland Public Service Commission in the matter of *The Investigation of the Process and Criteria for Use in Development* *of Requests for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland*, Case No. 9149, January 31, 2013.

Prepared Supplemental Direct Testimony of Frank Lacey on Behalf of Comverge, Inc., before the Maryland Public Service Commission in the matter of *The Investigation of the Process and Criteria for Use in Development of Requests for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland*, Case No. 9149, February 25, 2013.

Prepared Direct Testimony of Frank Lacey on Behalf of Comverge, Inc., before the Illinois Interstate Commerce Commission in the matter of *Ameren Illinois Company, d/b/a Ameren Illinois, Peak Time Rebate Program*, Docket No. 13-0105, May 30, 2013.

Oral Testimony of Frank Lacey on behalf of Comverge, Inc. at FERC Technical Conference in the Matter of *PJM Interconnection, L.L.C.*, Docket No. ER13-2108-000, October 11, 2013, discussing the appropriate information requirements for demand response offers made three years prior to a delivery year.

Oral Testimony and Cross Examination of Frank Lacey on behalf of Comverge, Inc, before the Utah Public Service Commission, *In the Matter of Rocky Mountain Power for Approval to Cancel Schedule 194*, Docket No. 13-035-136, September 12, 2013.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy before the Massachusetts Department of Public Utilities in the *Investigation as to the Propriety of Proposed Tariff Change* in response to the Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, Docket Number DPU 15-155, March 18, 2016.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy before the Massachusetts Department of Public Utilities in the *Investigation as to the Propriety of Proposed Tariff Change* in response to the Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, Docket Number DPU 15-155, April 28, 2016.

Oral Cross-examination Testimony of Frank Lacey on behalf of Direct Energy before the Massachusetts Department of Public Utilities in the *Investigation as to the Propriety of Proposed Tariff Change* in response to the Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid, Docket Number DPU 15-155, May 18, 2016.

Expert Rebuttal Report and Damage Summary of Frank Lacey, Response to the Review Submitted by Nathan Katzenstein, prepared on behalf of Astral Energy in the matter of *Treetop Development, et* *al. v. Astral Energy, et al.,* Docket #: BER-L-9414-13, Superior Court of New Jersey, Bergen County, December 9, 2016.

Expert Reply (Sur-rebuttal) of Frank Lacey, Reply to the Response Submitted by Nathan Katzenstein, prepared on behalf of Astral Energy in the matter of *Treetop Development, et al. v. Astral Energy, et al.,* Docket #: BER-L-9414-13, Superior Court of New Jersey, Bergen County, April 28, 2017.

Deposition of Frank Lacey on the topic of his Expert Rebuttal Report and Damage Summary prepared on behalf of Astral Energy in the matter of *Treetop Development, et al. v. Astral Energy, et al.*, Docket #: BER-L-9414-13, Superior Court of New Jersey, Bergen County, May 17, 2017.

Oral Testimony and Cross-examination Testimony on behalf of Astral Energy in the matter of *Treetop Development, et al. v. Astral Energy, et al.,* Docket #: BER-L-9414-13, Superior Court of New Jersey, Bergen County, June 5, 2017.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Clearview Energy before the Pennsylvania Public Utilities Commission in *Pennsylvania PUC v. Clearview Electric, Inc.*, Docket No. C-2016-2543592, January 9, 2017.

Prepared Direct Testimony of Frank Lacey on behalf of the Cape Light Compact before the Massachusetts Department of Public Utilities in the *Petition of NSTAR Electric Company and Western Massachusetts Electric Company d/b/a Eversource Energy for Approval of their Grid Modernization Plans*, Docket No. D.P.U. 15-122/123, March 10, 2017.

Oral Cross-examination Testimony of Frank Lacey (as part of the Cape Light Compact Panel of Witnesses) before the Massachusetts Department of Public Utilities in the *Petition of NSTAR Electric Company and Western Massachusetts Electric Company d/b/a Eversource Energy for Approval of their Grid Modernization Plans*, Docket No. D.P.U. 15-122/123, May 31, 2017.

Prepared Direct Testimony of Frank Lacey on behalf of the Retail Energy Supply Association before the Massachusetts Department of Public Utilities in the *Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. C. 164, § 94 and 220 C.M.R. § 5.00*, Docket No. D.P.U. 17-05, April 28, 2017.

Oral Cross-examination Testimony of Frank Lacey on behalf of the Retail Energy Supply Association before the Massachusetts Department of Public Utilities in the *Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution*

Rates for Electric Service Pursuant to G.L. C. 164, § 94 and 220 C.M.R. § 5.00, Docket No. D.P.U. 17-05, June 27, 2017.

Prepared Direct Testimony of Frank Lacey on behalf of the Retail Energy Supply Association before the New York Public Service Commission in the _Matter of Eligibility Criteria for Energy Service Companies_, Case No. 15-M-0127, in the _Proceeding on the Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-Residential Retail Energy Markets in New York State_, Case No. 12-M-0476, and in the _Matter of Retail Access Business Rules_, Case No. 98-M-1343, September 15, 2017.

Prepared Rebuttal Testimony of Frank Lacey on behalf of the Retail Energy Supply Association before the New York Public Service Commission in the _Matter of Eligibility Criteria for Energy Service Companies_, Case No. 15-M-0127, in the _Proceeding on the Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-Residential Retail Energy Markets in New York State_, Case No. 12-M-0476, and in the _Matter of Retail Access Business Rules_, Case No. 98-M-1343, October 27, 2017.

Oral Cross-examination Testimony of Frank Lacey on behalf of the Retail Energy Supply Association before the New York Public Service Commission in the _Matter of Eligibility Criteria for Energy Service Companies_, Case No. 15-M-0127, in the _Proceeding on the Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-Residential Retail Energy Markets in New York State_, Case No. 12-M-0476, and in the _Matter of Retail Access Business Rules_, Case No. 98-M-1343, November, 2017.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services and its Affiliates before the Virginia State Commerce Commission in the _Application of Virginia Electric and Power Company for Approval of 100% Renewable Energy Tariffs Pursuant to Subsection 56-577 A 5 and 56-234 of the Code of Virginia_, Docket No. PUR-2017-00060, August 23, 2017.

Oral Surrebuttal and Cross-examination Testimony of Frank Lacey on behalf of Direct Energy Services and its Affiliates before the Virginia State Commerce Commission in the _Application of Virginia Electric and Power Company for Approval of 100% Renewable Energy Tariffs Pursuant to Subsection 56-577 A 5 and 56-234 of the Code of Virginia_, Docket No. PUR-2017-00060, December 4, 2017.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy and its affiliates before the Commonwealth of Virginia State Corporate Commission in the _Application of Virginia Electric and Power Company for Approval of 100 Percent Renewable Energy Tariffs for Residential and Non-residential Customers Pursuant to SS 56-577 A 5 and 56-234 of the Code of Virginia_, Case No. PUR-2017-00157, April 17, 2018

Oral Direct and Cross-examination Testimony of Frank Lacey on behalf of the Retail Energy Supply Association before the Public Service Commission of the State of Delaware, *In the Matter of the Review of Customer Choice in the State of Delaware*, Docket No. 15-1693, April 19, 2018.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy and Direct Energy Solar before the Rhode Island Public Utilities Commission in the matter of *The Narragansett Electric Co. d/b/a National Grid's Proposed Power Sector Transformation (PST) Vision and Implementation Plan*, Docket No. 4780, April 25, 2018, (Case Settled).

Oral Testimony on behalf of the Advanced Energy Management Alliance before the Pennsylvania Public Utilities Commission *En Banc Hearing for Supplier Consolidated Billing*, Docket No. M-2018-2645254, June 14, 2018.

Prepared Supplemental Direct Testimony of Frank Lacey on behalf of Direct Energy and its affiliates before the Commonwealth of Virginia State Corporate Commission in the *Application of Virginia Electric and Power Company for Approval of 100 Percent Renewable Energy Tariffs for Residential and Non-residential Customers Pursuant to SS 56-577 A 5 and 56-234 of the Code of Virginia*, Case No. PUR-2017-00157, June 19, 2018.

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Default Service Pricing Has Been Wrong All Along

Allows Utilities to Maintain Dominance in Markets

By Frank Lacey, Electric Advisors Consulting

Default service prices have been wrong for two decades.

Most of the states that have implemented competition in electric and gas sales have employed a Provider of Last Resort, POLR, or default service to supply electricity to customers who do not select an alternative provider. Yet the utilities allocate few to no "costs to serve customers" to default service rates.

This practice has allowed the incumbent utilities to price default service below market rates. And it has allowed them to maintain unregulated monopoly-like power and dominant market positions in the energy markets in their respective service territories.

The failure to allocate costs appropriately to a utility business unit is in direct conflict with cost allocation guidance from the National Association of Regulatory Utility Commissioners, NARUC. Until the default service pricing distortion is corrected, utility default service providers will continue to hold an anti-competitive pricing advantage in the provision of retail electricity service.[1] Regulators should act to correct this major market flaw.

Default Service Rates Artificially Low

Several states have deregulated or restructured their energy markets to allow consumers to choose their own electric and or gas supplier. With few notable exceptions, the deregulation models adopted in these states called for the incumbent utility to become the POLR or default service provider.[2]

While initially envisioned to serve a small number of customers who needed a "last resort" provider, the market rules incorporated into most restructured markets placed all customers on last resort service at the inception of retail competition, making it more of a "default" service.

Because an appropriate amount of costs are not allocated to default service, customers are reluctant to leave their incumbent utility. They are receiving electricity that is subsidized by distribution rates.

The default service pricing subsidy provides the incumbent utilities with what are effectively unregulated monopolies. Default service customers are not being charged an amount that is reflective of the cost to serve them.

The lack of any meaningful cost allocations to default service allows (requires) the incumbent utilities in restructured states to understate the price of retail electricity. This practice effectively eliminates competitive suppliers from functioning in those markets.

This pricing error leads to numerous market flaws. Distribution rates are too high. Default service rates are too low. Customers are receiving incorrect and inappropriate price signals from their host utilities.

Customers who have switched to competitive suppliers are subsidizing those who stay on default service. And competitive suppliers are at a distinct pricing disadvantage compared to default service providers, allowing the utility market power to proliferate in retail energy markets.

This pricing incongruity allows utilities to maintain a stronghold over customers in their service territory. It also has given rise to claims about overcharging by competitive suppliers.

The failure to allocate costs appropriately to a utility business unit is in direct conflict with cost allocation guidance from NARUC.

Frank Lacey has worked in competitive energy markets since their inception as a consultant to utilities navigating restructuring and as a direct market participant once the markets opened. After more than twenty years in the industry, he launched Electric Advisors Consulting, in the fall of 2015. His focus is assisting clients with energy market issues – regulatory, strategic and business. His clients include energy market participants and end-use consumers. He can be reached at frank@eacpower.com.

Freestanding Default Service Business Couldn't Survive

It is easy to prove the anti-competitive pricing in default service. One only needs to contemplate how long a default service business could operate if it was removed from the distribution company but kept its current cost structure intact. The short answer is that it would survive for only a very short period of time – technically, not even a day.

Default service companies need to issue tens of thousands of invoices every day and then need to process revenues as they come in. But because no costs to serve customers are allocated to default service businesses, there would be no money to pay any employees to perform those functions, nor any other function involved in running a default service business.

The current default service businesses would be bankrupt in a matter of days, or even hours, if they were operated outside of the distribution utilities. Clearly, this is a fundamentally flawed

Fig. 1 Comparative Electric Customer Rates

Electric customer rates of switching from utility to competitive retail provider.

State	Utility	Percentage migration by customer count: Residential customers	Small and medium customers	Large customers
DC	PEPCO	15.0	32.1	N/A
MD	BGE	23.9	41.0	96.5
	PEPCO	19.8	42.8	87.9
	POT ED	10.8	32.4	90.3
	Delmarva	13.8	35.8	96.9
NJ	ACE	12.8	32.2	87.1
	JCPL	16.6	38.1	83.7
	PSEG	9.7	24.7	81.0
	RECO	6.9	18.4	74.5
PA	Duquesne	29.9	39.9	63.1
	Met-Ed	30.2	45.1	86.3
	PECO	31.0	46.0	91.0
	Penn Elec	26.1	42.2	88.1
	Penn Power	24.2	46.3	100.0
	PPL	41.3	53.7	70.5
	West Penn	24.7	32.8	91.9
NY	Central Hud	13.1	23.1	78.0
	Con Ed	22.8	29.8	91.6
	Nat Grid	16.1	38.5	80.2
	NYSEG	18.6	35.2	66.0
	O & R	33.5	45.9	26.4
	Rochester	16.2	42.0	93.2
Maine	State-wide	14.1	42.6	84.2
Delaware	Delmarva	9.8	32.2	

system and one that conflicts with all traditional rate-making standards.

Cost allocation is a fundamental tenet of utility ratemaking. The principles of cost allocation are fully endorsed by NARUC and should be applied to default service as they are to all other utility rates.

Allocations are required to appropriately assign fixed costs to multiple products or services that drive the costs. The principles of cost allocation are the foundation for nearly every (if not every) utility rate, aside from default service rates.

The NARUC Cost Accounting Manual states:

"While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that *service should be provided at cost*. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates. The cost principle applies not only to the overall level of rates, but to *the rates set for individual services, classes of customers, and segments of the utility's business*." Emphasis added.

NARUC has separately published cost allocation principles. The principles should be applied, according to NARUC "whenever products or services are provided between a regulated utility and its non-regulated affiliate or division." NARUC principles apply to default service, a business segment where many services are provided by the distribution company:

"The allocation methods should apply to the regulated entity's affiliates in order to *prevent subsidization* from and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa." Emphasis added.

NARUC states that the objective of its guidelines is to "lessen the possibility of subsidization in order to *protect monopoly ratepayers and to help establish and preserve competition* in the electric generation and the electric and gas supply markets." Emphasis added.

In fact, to ensure the competitiveness of markets, NARUC states that generally, "the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be *at the higher of* fully allocated costs or prevailing market prices." Emphasis added.

NARUC's objectives and guidelines have been ignored in pricing default service.

Market Distortions

The default service pricing anomaly has given rise to many market distortions and has resulted in competitive suppliers being cast in a negative light in many jurisdictions. It has caused competitive suppliers to spend millions of dollars in unnecessary marketing costs, regulatory costs and legal and compliance costs.

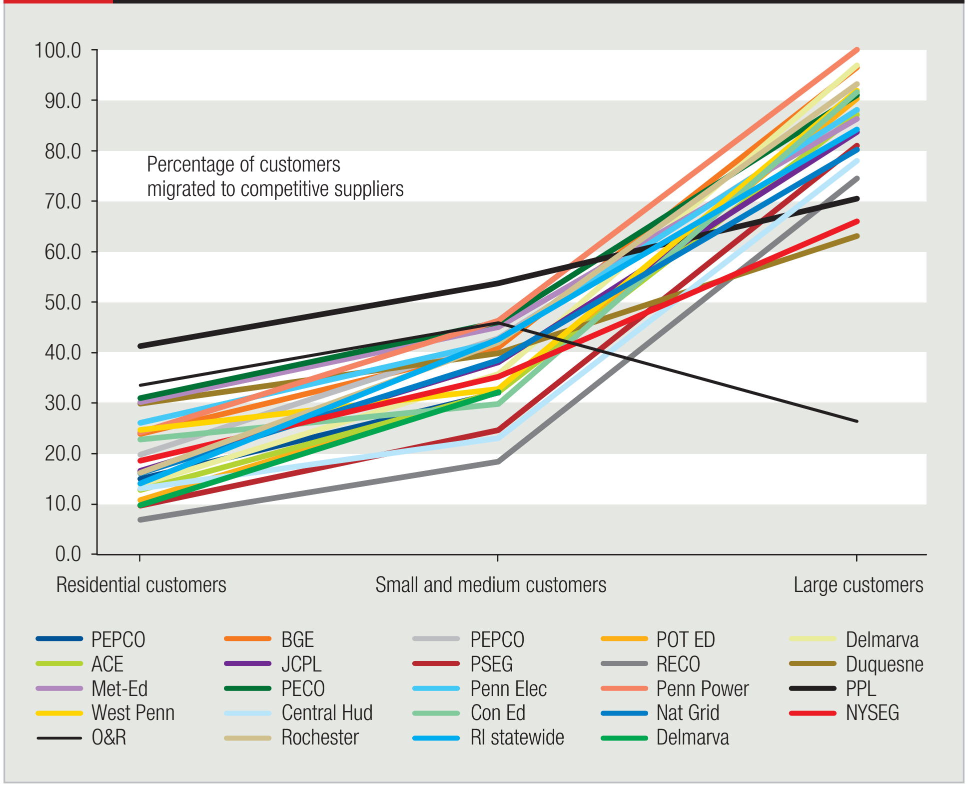
Most important, it has resulted in customer harm from being constrained to the utilities' "no service" products and from the lack of product options that are available in more competitive markets.

Table One details the percentage of customers who have chosen a competitive electric supplier across many of the deregulated electricity markets. Despite two decades of competition and dozens of suppliers vying for customers in every market, the incumbent utility stronghold on the market, especially over residential customers, is painfully clear.

See Figure One.

At the low end, we see single digit migration rates for residential customers to competitive suppliers. The Pennsylvania market shows the most promising residential migration numbers – ranging from the mid-twenty percent range to just over forty percent in PPL's service territory.

FIG. 2 CUSTOMER MIGRATION TRENDS ARE CONSISTENT ACROSS MARKETS



States that have deployed municipal aggregations to facilitate customer migration are not included in this chart because aggregations are simply a regulatory fix that masks the pricing problem in the short-term. Municipal aggregations do not solve the pricing problems over time.

Figure Two shows the same data in graphical form. The utilities all show the same migration trends. Small customers do not migrate away from the utilities while the largest customers participate in the competitive markets at very high penetration levels.[3] See Figure Two.

Artificially Low Default Service Prices Harms Customers

Under an appropriate cost allocation approach, the customers will pay, on net, the same amount every year. Cost allocation does not cause an increase in costs to customers. It only moves costs to different buckets.

Because there is no total cost increase to customers with an appropriate cost allocation, the argument that the customers are better off under the current pricing model is flawed. In fact, because of the inaccurate pricing signal with the current model, customers are harmed in meaningful ways.

Most important, customers are not receiving the appropriate price signal for energy. This results in a potential to over-consume energy provided by default service providers, yielding what could be a higher overall monthly cost to the customer than would otherwise incur if the electricity was priced appropriately.

Customers who have switched to competitive suppliers are subsidizing those who stay on default service.

The distribution subsidy also creates a barrier to evaluating competitive offers. It is impossible for customers to assess fairly a competitive offer when the utility price is artificially low.[4] Because the basic competitive market product would be viewed as uneconomic by the consumers, competitive suppliers are less likely to invest fully in the market, depriving customers of other products and services that the suppliers might be inclined to offer in that market. Foregone products and services include many that might reduce a consumer's consumption overall, benefitting the customers and the environment.

Finally, the distribution subsidy results in a distribution rate that is too high. Customers who have moved away from the utility are forced to pay costs that benefit customers who remain on default service.

Recent Analyses Reveal Subsidies

Substantial analyses seeking to understand the magnitude of the distribution subsidy have been performed in two recent distribution rate cases. The results of those analyses have been presented to utility commissions in Pennsylvania and New

Jersey in the form of expert testimony in those respective cases. These analyses show that the subsidy is significant – a penny or more per kilowatt-hour – as high as fifteen percent of the default service rate.

In PECO's rate proceeding, Pennsylvania Public Utility Commission's docket R-2018-3000164, NRG Energy Company provided an analysis of PECO's distribution rates to determine if any distribution costs were being used to subsidize PECO's default service rates. The analysis showed that the subsidy of PECO's default service by PECO's distribution business amounts to 1.25 cents per kilowatt-hour for residential customers.

If that amount was properly allocated to PECO's default service rates, it would increase those rates by approximately fifteen percent. Of course, if the costs were properly allocated to default service, the corresponding cost components from the distribution rates would decrease by the same amount.

In PSEG's rate proceeding, New Jersey Board of Public Utilities docket ER18010029, I undertook on behalf of Direct Energy, a similar analysis. My analysis showed that the subsidy that PSEG distribution rates were providing to PSEG's default service amounts to 1.0 cents per kilowatt-hour to residential customers. Because PSEG's default service rates are higher than PECO's, an additional 1.0 cents per kWh represents a subsidy of about eight percent to residential default service rates.

In the PSEG rate case, not enough information was provided by the utility to determine the magnitude of costs (working capital, credit, bad debt, etc.) that should be directly assigned to default service. As a matter of conservatism in my analysis, I assumed that those should be only partially allocated.

If direct costs were assigned properly to default service and indirect costs were allocated appropriately, the actual costs to serve default service customers in New Jersey could be in the range of 1.5 cents per kilowatt-hour.

With default service rates ranging from the low single digits to the low teens in cents per kilowatt-hour in markets across the country, and the unallocated funds (or subsidies) ranging from 1.0 to 1.5 cents per kilowatt-hour, this subsidy can be valued anywhere between eight percent and fifty percent of a monthly default service charge. A subsidy of that magnitude, or that scale of utility "discount" severely distorts the market, unfairly advantages the utilities over competitive service providers and harms customers.

Conclusion

Appropriately allocating costs currently paid by distribution customers to default service is a critical next step in creating more competitively neutral energy markets in the United States. This one step will not create the perfect markets, but it will remove a significant anti-competitive pricing advantage held by monopoly utilities.

It will also remove a subsidy that competitive supply customers are forced to pay to benefit default service customers, and it will help create a market that competitive suppliers are more willing to invest in. At the same time, if implemented correctly, it keeps distribution utilities financially whole. It is a win-win-win solution benefitting all market participants. PUF

Endnotes:

1. While this article is focused on electricity markets, the same pricing problems exist in gas markets. The costs to serve customers are not allocated to those customers' rates. Instead, they are charged to distribution customers.
2. Most of the deregulation models deployed in the U.S. are generally very similar. In contrast, Texas electricity customers and Georgia natural gas customers were placed with market participants at the inception of those markets and default service in those markets is truly a "last resort" service, not a "default" or "do nothing" service.
3. The one anomaly revealed in this chart is in the Orange & Rockland Utility in New York. It shows an uncharacteristic low level of customer migration at the large end of the customer spectrum. It is not clear whether this is a data error on the NY PSC website, or if there is a market anomaly in that market that results in the largest customers remaining with the utility.
4. Under no circumstance should any price, including the utilities' default service price, be considered a benchmark price. The default service price is for a specific product with a specific set of parameters associated with it. Additionally, as this article notes, it is heavily subsidized. It comes with a certain level of service and a limited ability for it to be modified in any way to meet customers' needs. Regardless, regulators in many states have mandated rules that require a comparison of all products to the utility default service price. These requirements include for example, a requirement that the default service price be placed on a customer's invoice, even if the customer is being served by another supplier, with a different product. Some have required that all sales interactions include a notice of the utilities' default service price.

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Default service pricing – The flaw and the fix
Current pricing practices allow utilities to maintain market dominance in deregulated markets

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ABSTRACT

Utility default service has been priced incorrectly for two decades. Incumbent utilities serving as default service providers for both electricity and gas allocate few to no "costs to serve" to default service rates. The indirect costs not allocated include billing, customer care, enrollments, metering, and other overhead and add up to billions of dollars annually. These costs are paid in distribution rates. The resulting rate for utility-provided default service is a below-market price, allowing the utilities to maintain dominant market positions in the retail markets for residential and small commercial customers. This pricing practice distorts the relevant retail electric and gas markets and harms customers and the markets. NARUC cost allocation guidelines advocate that the cost of utility resources used in the provision of default service should be allocated to that service. This paper presents a Default Service Equalization Adjustment Mechanism ("D-SEAM") that when deployed properly, will provide the default service utilities with a tool to allocate an appropriate amount of costs to default service rates and then adjust that allocation on a monthly basis to ensure the distribution utility is made whole financially as customers migrate off of default service. Without an appropriate allocation of cost to default service, incumbent utilities will maintain a dominant market position in the retail markets for residential and small commercial customers as a result of the significant subsidy provided by the distribution rates. Utilities should adopt, and/or the regulators should compel the adoption of a complete and appropriate allocation of costs to default service. It is only with this allocation that customers will be able to reasonably compare market offerings.

1. Introduction

1.1. Default service prices have been wrong for two decades

Several states have restructured their electricity and/or gas markets to allow for customer choice of energy suppliers. Most of these states have implemented a Provider of Last Resort ("POLR") provider or Default Service provider to provide electricity to customers who do not select an alternative provider. As long as default service remains the benchmark against which other offers are compared[1], it should be priced so that all of the costs incurred to provide default service are included. For it is only in that circumstance when competitive retail energy markets empower customers to meaningfully compare energy offers. Testimony presented in recent rate proceedings for PECO electric distribution utility in Pennsylvania and PSEG's electric and gas distribution utilities in New Jersey reveal the magnitude of the pricing subsidies that are present in those markets. The practice of not allocating costs appropriately to a utility business unit is in direct conflict with cost allocation guidance from the National Association of Regulatory Utility Commissioners ("NARUC"). Until the pricing distortion is corrected, utility default service providers will continue to hold an anti-competitive pricing advantage in the provision of what should be competitive retail electricity service. Regulators should act to correct this major market flaw.

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[1] For several reasons, including those discussed within this paper, utility-provided default service products and prices should not be a benchmark to compare any competitive service offerings. The default service price is for a very specific product with a very specific set of parameters associated with it. This rate is often reconcilable and reflects a price from a prior point in time in the market. Additionally, as this article notes, default service is heavily subsidized. It comes with a certain level of service and a very limited ability for it to be modified in any way to meet customers' needs. Regardless, regulators in many states have mandated rules that require a comparison of all products to the utility default service price. These requirements include for example, a requirement that the default service price be placed on a customer's invoice, even if the customer is being served by another supplier, with a different product. Some have required that all sales interactions include a notice of the utilities' default service price.

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The majority of states that have restructured retail energy markets report statistics on customer migration away from the incumbent utilities. This data shows clearly that the incumbent utilities in restructured states continue to hold strong market dominance in the residential and small commercial markets. For example, after nearly 20 years of competition, the majority of restructured states show migration rates of less than 20% of the residential electricity customers.[2]

The explanations proffered by the so-called "energy experts" all miss the simple truth – the incumbent utilities still hold vast market powers granted to them by their respective regulators. Most notably, the cost of providing default service is nearly fully- (and in some cases fully-) subsidized by the host utility's distribution customers. Yes, customers typically pay the full price for the electrons they receive. Customers, however, are not charged for billing, IT, overhead, or any other costs that should rightfully be allocated to default service. The simple thought experiment to see if appropriate costs are being allocated to the default service business is to imagine what would happen if default service was severed from the utility's distribution business. Under this imaginary scenario, nearly every default service program would be bankrupt in a matter of days, if not hours, if it was removed from the distribution business. This simple example should allow the reader to clearly see that utilities are not allocating adequate costs to default service.

2. Background

Several states within the United States have deregulated or restructured their retail energy markets to allow consumers to choose their own electric and/or gas supplier. While the utilities in these regions continue to maintain monopoly franchise rights over their "pipes and wires" businesses, their electric generation and gas supply businesses are now subject to competitive forces and customer choice of supplier. With few notable exceptions, the deregulation models adopted in these states called for the incumbent utility to become the POLR or default service provider. While initially envisioned to serve a small number of customers who were in need of a "last resort" provider, the market rules incorporated into most restructured markets placed all customers on "last resort" service at the inception of retail competition[3]. Because "last resort" became such an inappropriate phrase for what utility service has become, the name has morphed to "standard offer" or "default service" – the service for customers who fail to choose a competitive alternative. Unfortunately, embedded in this process are default service prices that are heavily subsidized by the host utilities' distribution companies. As a result, default service customers are misled about their retail market options and thus, frequently remain with their incumbent utility.

Some default service providers pass along some direct costs to their customers, such as the cost of credit to procure power in the open market. Some providers pass on no costs at all beyond the direct cost of the energy provided. No incumbent utility default service provider in the US passes along any indirect costs to its default service business. The indirect costs incurred to provide service to default service customers amount to billions of dollars annually and are being paid by distribution customers. This distorts significantly the retail energy markets, providing the incumbent default service provider with a pricing advantage that allows them to maintain market dominance in the residential and small commercial customer segments.

These subsidies are the primary reason that retailers focus on nonprice issues and offer many value-added products and services. It is simply not practical to compete with standard offer service on price alone. In short, the default service rates offered to customers by incumbent utilities are artificially low, which leads to numerous market flaws: distribution rates are too high; default service rates are too low; customers are receiving incorrect and inappropriate price signals from their host utilities; consumers are not provided adequate information to make informed energy decisions; and customers who have switched to competitive suppliers are subsidizing those who stay on default service. This pricing incongruity allows the incumbent default service providers to maintain market dominance over customers in their service territories and it also has given rise to bogus claims of "overcharging" by competitive suppliers.

3. Data from recent analyses

Substantial analyses seeking to understand the magnitude of the distribution subsidy have been performed in recent distribution rate cases. The results of those analyses have been presented to Utility Commissions in Pennsylvania and New Jersey in the form of expert testimony in those cases. These analyses show that the subsidy is significant – a penny or more per kilowatt-hour – or more than 10% of the default service rate.

In PECO's rate proceeding (PA PUC Docket No. R-2018-3000164), NRG Energy Company presented an analysis of PECO's distribution rates that showed the subsidy of PECO's default service by PECO's distribution business amounts to 1.25 cents per kilowatt-hour for residential customers.[4]

In PSEG's rate proceeding (NJ BPU Docket No. ER18010029), Frank Lacey (the author of this article), an energy markets consultant and president of Electric Advisors Consulting, undertook on behalf of Direct Energy, a similar analysis that showed the PSEG distribution rates were providing default service subsidies of 1.0 cent per kilowatt-hour to residential customers and 0.67 cents per kWh to C&I customers.[5]

4. Proposed solution

The distribution companies should allocate the portion of costs incurred to operate the default service business to the that business and collect those costs from its customers on the energy portion of those customers' invoices. In order for the distribution company to fully collect its regulated revenue requirement, the distribution companies should also implement crediting, balancing and true-up mechanisms to ensure that it is never over- or under-collecting.

4.1. Cost allocation mechanism

Distribution resources that are used in the functioning of the default service business should be identified. The costs associated with these resources should be quantified as they would be in a rate proceeding. Once the bucket of costs is identified, an appropriate allocation

[2] This paper focuses on competitive electricity markets. The same dynamics discussed in this paper are also present in the competitive gas markets. The distribution companies significantly subsidize the commodity price by failing to allocate costs to serve default service customers. The solutions provided in this paper are applicable to gas distribution companies as well.

[3] A few deregulation models were implemented differently, and customers were immediately placed into the competitive market upon inception of the market. Notably, Texas electricity customers and Georgia natural gas customers were placed with market participants at the inception, or shortly after the inception of those markets.

[4] Direct Testimony of Chris Peterson on Behalf of NRG Energy Company, Pennsylvania Public Utility Commission v. PECO Energy Company, Docket No. R-2018-3000164, June 26, 2018.

[5] Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy and its affiliates before the New Jersey Board of Public Utilities, *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16, Electric and B.P.U.N.J. No. 16, Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 and GR18010030, OAL Docket No. PUC 01151-18, August 6, 2018.

approach should be applied so that costs to run the default service business are properly attributed to that business.

Based on the numbers presented by PSEG in its recent rate proceeding, approximately $300 million in expenses (out of a total of $900 million) and about $1.3 billion in rate base assets (out of a total of $5.7 billion) were identified as utility resources or costs that were utilized in the provision of default service and as such, these costs should be partially allocated to default service.[6]

The most logical allocator to apportion these shared costs is revenue as the majority of the shared costs are incurred in the revenue or cash management function. These costs include those for the billing system, accounting and finance, metering, and others.

4.2. True-up mechanism

If a static, one-time cost allocation is made to default service, as customers migrate to competitive supply, the utility would not be able to collect fully its distribution revenue requirement. In the PSEG rate case, a Default Service Equalization Adjustment Mechanism ("D-SEAM") was proposed to address that shortfall.[7] The D-SEAM does not require a change to the overall distribution revenue requirement or the resulting distribution rates. Instead, the D-SEAM allocation mechanism includes a monthly upward cost adjustment to default service customers and at the same time, it calls for an incremental cost credit to distribution customers, resulting in financial neutrality to the utility. As customers migrate to competitive supply, the D-SEAM collections decrease, but at the same time, so would the distribution credit to customers. The D-SEAM would operate in almost the exact same manner that many decoupling mechanisms are implemented, although calculations and adjustments could be implemented monthly.

As customers migrate away from default service, this ratio of revenues is certain to change, however, the subset of systems, infrastructure and people utilized to support default service will not change. Therefore, only the allocation factor changes with customer migration. The table below shows how the mechanism can be used to keep the utility whole as migration away from default service occurs (Table 1).

As customer migration occurs, the charges and credits change, but the total distribution collections remain constant. Ultimately, if every customer was on a competitive service supply option, there would be no allocations and no credits.

5. Freestanding default service businesses could not survive

To understand the foolishness of the current models, one only needs to contemplate how a default service business could operate if it was removed from the distribution company but kept its current cost structure intact. The short answer s that it would survive for only a very short period of time – technically, not even a day. If nothing else, a default service business needs to process tens of thousands of invoices and payments every day. In reality, the list of utility services utilized in the provision of default service is quite lengthy. Under the current framework, there would be no funds to pay for any of those services. Clearly, this is a fundamentally flawed system.

Table 1
Sample Calculations Showing D-SEAM and D-SEAM Impact on Distribution Revenue Collections.

Time Period	Number of Dist Customers	Average Dist Kwh/cust/month	Total Dist Revenue Requirement ($)	Distribution costs allocable to BGS (30% of all costs)	Retail Choice Customers	Default Service Customers	Revenue-based Allocation Ratio to D-SEAM	Costs Allocated to D-SEAM	D-SEAM per Default Service Customer ($/month)	D-SEAM Credit	D-SEAM Credit per Dist customer ($/month)	Total Distribution Collections ($)
0	1,600,000	577	46,160,000	13,848,000	–	1,600,000	0.50	6,924,000	4.33	6,924,000	4.33	46,160,000
1	1,600,000	577	46,160,000	13,848,000	200,000	1,400,000	0.47	6,462,400	4.62	6,462,400	4.04	46,160,000
2	1,600,000	577	46,160,000	13,848,000	800,000	800,000	0.33	4,616,000	5.77	4,616,000	2.89	46,160,000
3	1,600,000	577	46,160,000	13,848,000	1,000,000	600,000	0.27	3,776,727	6.29	3,776,727	2.36	46,160,000
4	1,600,000	577	46,160,000	13,848,000	1,599,999	1	0.00	0	0.00	0	0.00	46,160,000

[6] The rate proceeding did not adequately identify the subset of costs, such as working capital attributable to default service or wholesale procurement costs that should be directly assigned to default service business. As such, those direct costs were included in the analysis as an indirect cost and included in the set of costs that should be allocated to default service. As a result, the final recommendation of a 1.0 cent per kWh allocation to default service is likely understated.

[7] PSEG's default service is called Basic Generation Service or BGS. The equalization adjustment was referred to as "BEAM" in the PSEG rate proceeding.

6. NARUC principles require allocations to default service

The principles of cost allocation are fully endorsed by NARUC and should be applied to default service as they are to all other utility rates. The principles of cost allocation are the foundation for nearly every (if not every) utility rate, aside from default service rates. The principles of cost accounting are neither new nor novel to utility rate making personnel or regulators who approve rates. Yet despite the long history of cost allocation in the industry, the default service businesses have been allowed to operate since the inception of deregulation without an appropriate allocation of costs to serve default service customers.

The NARUC Cost Accounting Manual states:

"While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates. The cost principle applies not only to the overall level of rates, but to the rates set for individual services, classes of customers, and *segments of the utility's business*. Cost studies are therefore used by regulators for the following purposes:

- To attribute costs to different categories of customers based on how those customers cause costs to be incurred.
- To determine how costs will be recovered from customers within each customer class.
- To calculate costs of individual types of service based on the costs each service requires the utility to expend.
- To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets.
- To separate costs between different regulatory jurisdictions."[8] (emphasis added).

These observations from NARUC are especially prescient given the date of the Cost Allocation Manual – January 1992. At that point in time NARUC was envisioning an allocation of costs of monopoly services offered by a utility operating in both monopoly and competitive markets. Even though it is likely the NARUC Manual did not envision default service as it is being offered today, the principles hold true from an accounting perspective and from a regulatory rate-making perspective and should be applied to default service.

Notably, NARUC's Manual expressly calls out costs allocated to "segments of the utility's business". In other words, it is appropriate to allocate costs to each business segment, even if it is not a separate business unit with profits and/or losses attached to it. Despite the foresight from NARUC, this guidance has been ignored by utilities in the provision of default service. This manual, dating back over 25 years is still available on the NARUC website.[9]

NARUC has separately published cost allocation principles. The principles should be applied, "whenever products or services are provided between a regulated utility and its non-regulated affiliate or division".[10] Under NARUC's first identified principle, direct costs "should be collected and classified on a direct basis for each asset, service or product provided."[11] The set of direct costs that should be charged to default service include, but is not limited to, the cost of credit, the cost of wholesale market departments, the costs of procurement, working capital, bad debt, the cost of communicating environmental attributes of default service supply (where required), and the cost of other regulatory requirements imposed on default service providers.

NARUC principles further apply to default service stating: "The allocation methods should apply to the regulated entity's affiliates in order to *prevent subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates*, and vice versa."[12] (Emphasis added.)

NARUC describes that the objective of its guidelines is to "lessen the possibility of subsidization in order to protect monopoly ratepayers and to *help establish and preserve competition in the electric generation and the electric and gas supply markets*."[13] (emphasis added) In fact, to ensure the competitiveness of markets, NARUC states that generally, "the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the *higher of fully allocated costs or prevailing market prices*."[14] (emphasis added) NARUC's cost allocation guidance and objectives have been ignored for two decades and the data shows that the incumbent utilities' monopoly-like stronghold over customers, especially residential and small commercial customers, remains.

7. Default service pricing harms markets

7.1. Default service providers maintain market dominance

The default service pricing anomaly results in a significant subsidy that provides the incumbent utilities default service businesses with anti-competitive pricing power. Default service customers are simply not being charged an amount that is reflective of the cost to serve those customers. The lack of any meaningful cost allocations to default service allows (requires) the incumbent utilities in restructured states to understate the price of retail electricity and eliminates competitive suppliers from functioning effectively in those markets.

In an ironic submission to the New York Public Service Commission, Commission staff offered the results of a Herfindahl–Hirschman Index ("HHI")[15] analysis, while trying to show market power among competitive suppliers. However, what the results actually showed is that each of the New York electricity markets was "highly concentrated" when the analysis included the incumbent utility (with HHI scores above 7000) but was unconcentrated without the incumbent utilities (with HHI scores as low as 420).[16] Rather than showing market power among competitive suppliers, this analysis clearly demonstrates the market dominance of the New York utilities. Commission staff testified further that the 23 largest competitive electric suppliers were serving less than 20% of the New York residential market.[17] That means that on average, the 23 largest competitive electric

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[8] NARUC, Electric Utility Cost Accounting Manual, January 1992, found at *http://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD*

[9] See: https://pubs.naruc.org/pub.cfm?id=53A20BE2-2354-D714-5109-3999CB7043CE

[10] NARUC, http://pubs.naruc.org/pub/539BF2CD-2354-D714-51C4-0D70A5A95C65

[11] Ibid, Section B.1.

[12] Ibid, Section B.4.

[13] Ibid, Section D.

[14] Ibid, Section D.1.

[15] According to the US Department of Justice, the HHI is a commonly accepted measure of market concentration. The HHI is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers. The HHI considers the relative size distribution of the firms in a market. It approaches zero when a market is occupied by a large number of firms of relatively equal size and reaches its maximum of 10,000 points when a market is controlled by a single firm. Agencies generally consider markets in which the HHI is between 1,500 and 2,500 points to be moderately concentrated and consider markets in which the HHI is in excess of 2,500 points to be highly concentrated. *See* U.S. Department of Justice & FTC, *Horizontal Merger Guidelines* § 5.3 (2010).

[16] Prepared Direct Testimony of Joel Andruski, Associate Economist, Office of Market and Regulatory Economics, State of New York, Department of Public Service, *In the Matter of ESCO Track I Proceeding*, Cases 15-M-0127, 12-M-0476 and 98-M-1343, September 2017.

[17] Prepared Direct Testimony of the NY PSC Staff Panel: Bruce E. Alch, Chief, Retail Access and Business Advocacy, Office of Consumer Services; Craig Carroll, Utility Analyst 2, Office of Consumer Services; Peter Lavery, Utility Analyst, Office of Accounting, Audits and Finance; Kristine A. Prylo, Principal Utility Financial Analyst, Office of Accounting, Audits and Finance; David Shahbazian, Utility Auditor II, Office of Accounting, Audits and Finance, State of New York Department of Public Service, *In the Matter of ESCO Track I*

suppliers each hold less than a 1% market share, while one New York utility still holds an 87% share in the residential market in its service territory.

The New York Staff's HHI analysis effectively proves the utilities dominance in New York. The same result would be found in nearly every other deregulated market. The question then is: why do the utilities hold such a dominant position? It is clearly not the lack of interest from competitive suppliers. After all, the New York Staff cites to the "23 largest" suppliers, indicating that there are many more than 23 vying for customers' business. Do customers endear themselves to the utilities in every market? Not likely. Do the utilities offer one better product than the list of all products offered by competitive suppliers? Not likely. Or is the utilities pricing subsidy simply too great for competitive suppliers to overcome? Without performing any formal analysis on these first two questions, the answers seem obvious. The utility pricing advantage brought on by a lack of cost allocation is simply too great for the suppliers to overcome. All energy companies are purchasing power from the same wholesale markets. Utilities simply do not pass on the costs to service their customers. The pricing incongruity could not be more evident.

Because competitive suppliers must include all of their operating costs in their supply prices in addition to the wholesale cost of energy, competitive prices are frequently higher than those of the subsidized default service rates. Instead of regulators fixing the default service pricing, many have instead lobbed allegations of "overcharging" at the competitive suppliers.[18] Regulators and consumer advocates have launched investigations and suggested that residential markets be closed. As a result, competitive suppliers have spent millions of dollars defending their actions and fighting to maintain a presence in the markets.

7.2. Customer migration trends are consistent

The New York customer switching results discussed above are not unique. Table 2 below details the percentage of customers who have chosen a competitive electric supplier across many of the deregulated electricity markets. After two decades of competitive markets, we see a similar pattern of migration rates of customers to competitive suppliers across the restructured markets[19] .

The results in Table 2 are not unexpected. In order to compete with default service, a competitive supplier has to either wait for a cycle in the wholesale markets that will allow for a more economic offering than default service, or the supplier has to offer a better, typically more expensive product. It is difficult to compete with the subsidized default service price.

Chart 1 below shows the same data in graphical form. The graph shows that the migration problem is not unique to any one utility jurisdiction. Small customers do not migrate away from the utilities while the largest customers participate in the competitive markets at very high penetration levels[20] . It is not clear whether the outlier in the Large Customer category reflects a data error on the NY PSC website, or if there is a market anomaly that results in the largest customers in that market remaining with the utility.

Table 2
Electric Customer Retail Choice Migration Rates[a.]

State	Utility	Percentage of Rate Class Switching By Customer Count: Residential	Small and Medium	Large
DC[b,c]	PEPCO	15.0	32.1	N/A
MD[d]	BGE	23.9	41.0	96.5
	PEPCO	19.8	42.8	87.9
	POTED	10.8	32.4	90.3
	Delmarva	13.8	35.8	96.9
NJ[e]	ACE	12.8	32.2	87.1
	JCPL	16.6	38.1	83.7
	PSEG	9.7	24.7	81.0
	RECO	6.9	18.4	74.5
PA[f]	Duquesne	29.9	39.9	63.1
	Met-Ed	30.2	45.1	86.3
	PECO	31.0	46.0	91.0
	Penn Elec	26.1	42.2	88.1
	Penn Power	24.2	46.3	100.0
	PPL	41.3	53.7	70.5
	West Penn	24.7	32.8	91.9
NY[g]	Central Hud	13.1	23.1	78.0
	Con Ed	22.8	29.8	91.6
	Nat Grid	16.1	38.5	80.2
	NYSEG	18.6	35.2	66.0
	O & R	33.5	45.9	26.4
	Rochester	16.2	42.0	93.2
Maine[h]	State-wide	14.1	42.6	84.2
Delaware[i]	Delmarva	9.8	32.2	

[a]Data in this table gathered from each state's PUC or related website. Each state has differing definitions for C&I customer classes. Data from Ohio, Illinois and Massachusetts are not included in this table because each jurisdiction has engaged in robust community aggregation programs. Rhode Island data is not presented because Rhode Island does not report by rate class, the number of customers not participating in retail choice programs, so percentages by rate class cannot be calculated. Connecticut data is not shown here as its last reported data period is year-end 2014 and it also does not break down enrollment data by rate class.
[b]See: https://dcpsc.org/PSCDC/media/PDFFiles/Electric/electric_sumstats_no_cons.pdf. (Sept. 2018 data).
[c]See: https://dcpsc.org/PSCDC/media/PDFFiles/Electric/electric_sumstats_cons_dmnd.pdf. (Sept. 2018 data).
[d]See: https://www.psc.state.md.us/electricity/electric-choice-monthly-enrollment-reports/. (August 2018 data).
[e]See: https://www.state.nj.us/bpu/pdf/energy/edc07.pdf. (August 2018 data).
[f]See: https://www.papowerswitch.com/sites/default/files/PAPowerSwitch-Stats.pdf. (Sept 2018 data).
[g]See:http://www3.dps.ny.gov/W/PSCWeb.nsf/All/4759ECEE7586F24B85257687006F396E?OpenDocument (December 2017 data).
[h]See: https://www.maine.gov/mpuc/electricity/choosing_supplier/migration_statistics.shtml. (September 2018 data).
[i]See: https://depsc.delaware.gov/electric-regulation/#consumer. (April 2018 data).

7.3. Improper default service pricing harms Consumers

Customers are receiving an artificially low energy-price signal. This incorrect signal results in over-consumption of energy provided by default service providers. Because most residential customers are still on default service, the pricing anomaly results in system-wide over-consumption of electricity, increasing market prices for all consumers. On net, the artificially low price might actually yield what could be higher overall monthly costs to all customers because wholesale prices are impacted by increased consumption levels.

It is also impossible for customers to assess fairly a competitive offer

(*footnote continued*)
Proceeding*, Cases 15-M-0127, 12-M-0476 and 98-M-1343, September 2017.*

[18] In the aftermath of the Polar Vortex in 2014, a handful of suppliers charged higher prices than were typical in the market at the time. Regulators in some markets determined that certain suppliers acted in bad faith and penalized them. However, the recent analyses presented that allege systemic overcharging have incorrectly and inappropriately compared market-based electricity products to the subsidized default service rates on an apples-to-apples basis.

[19] States that have implemented municipal aggregations programs are not included in Table 2. Municipal aggregations might lead to more robust migration numbers, but they are only a short-term regulatory fix that temporarily masks the distribution subsidy. Municipal aggregations do not solve the pricing incongruity over time.

[20] The research on this paper and in support of the PSEG rate case showed that the subsidy for larger customers is smaller, on a per-kWh basis, than the subsidy for residential customers.

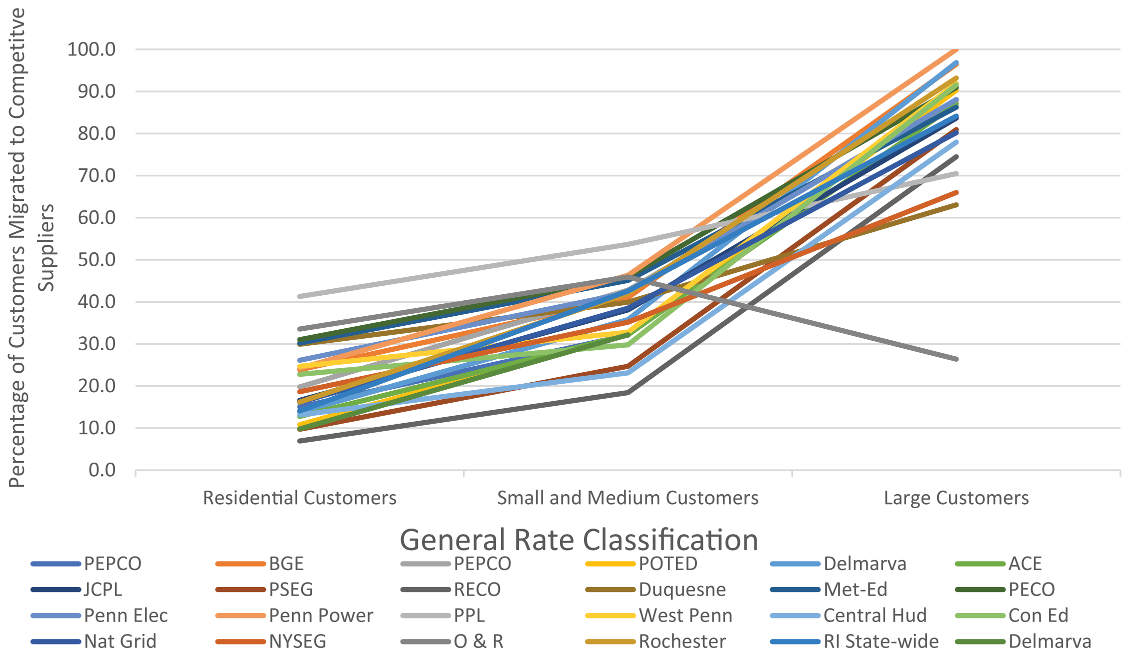

Chart 1. Customer Migration Trends are Consistent Across Markets.

when the utility price is artificially low[21] . Because the basic competitive commodity-only product would be viewed as uneconomic by the consumers, suppliers are less likely to invest fully in the market, depriving customers of other products and services including many that might reduce a consumer's overall consumption, which would benefit the customers and the environment. These products and services are available in the more competitive regions of the country but are not as readily available where the subsidized default service rates stifle competition.

Finally, the distribution subsidy results in a distribution rate that is too high. Customers who have moved away from the utility are forced to pay costs that benefit customers who remain on default service.

The lack of residential and small commercial customer energy savings options, products and services is the result of a failed regulatory paradigm. It is not a reflection of a failed market.

8. Arguments against Cost allocation are flawed

Stakeholders have generally proffered four arguments against allocating indirect retail costs to default service. The typical arguments are:

1) The costs are not avoidable and will be incurred by the distribution business whether or not they provide default service;
2) If costs are allocated to default service, the distribution utility will not be able to recover its full distribution revenue requirement as customers migrate to competitive suppliers;
3) Allocation of costs serves no purpose other than to increase rates on customers so that competitive suppliers can better compete with utility pricing; and
4) Utilities do not earn a profit on the provision of default service, so an allocation of costs is not needed.

All of these arguments are flawed.

8.1. Avoidable versus allocable costs

Simply stated, avoidable costs are direct costs. Fixed costs, which typically serve multiple purposes are considered indirect costs and should be allocated to the businesses which benefit from the resource. Direct or avoidable costs should be directly assigned (not "allocated") to the business unit incurring the costs. The existence of avoidable/direct costs, however, does not mean that allocable/indirect costs don't exist. In order for businesses to properly price products and services, indirect costs must be appropriately allocated to the cost centers benefiting from the incurrence of the costs.

Our economy is replete with examples of businesses that allocate costs to more than one product, service or business unit. But we do not need to look past the rate cases prevalent in the utility industry to see cost allocations implemented. Under the theory of avoidable costs, one could argue that commercial customers shouldn't pay for distribution wires because if the commercial customers left the grid, the utility would still need to have the distribution wires in place to service residential customers. Of course, that argument is foolhardy. The cost of the distribution wires and services related to it are largely fixed costs that benefit all rate classes and are therefore allocated to all rate classes based on cost causation principles. It is inappropriate that utilities do not similarly assign direct costs and allocate an appropriate amount of indirect costs to default service.

8.2. Cost recovery

Utilities have argued against allocations to default service because if costs are allocated to that service and customers move to competitive supply, the utility will not be able to fully recover its allowed rates. This argument assumes a static accounting paradigm. If a utility simply lowered its distribution rate by one cent per kWh and increased default service rates by one cent per kWh, that argument would hold some validity. Further accounting and pricing tools can be developed that would ensure the utility is kept whole. The D-SEAM described above was presented in the PSEG rate case and fully resolves the cost recovery issue.

The cost recovery argument is a red herring. Utility tariffs are chock full of riders, true-ups, monthly adjustments and "make whole" mechanisms. It is clear that a true-up mechanism can be deployed that will

[21] Under no circumstance should any price, including the utilities' default service price, be considered a benchmark price. See fn 1, supra.

ensure that default service customers are seeing a competitive energy price that will also ensure utilities are fully compensated for their revenue requirements.

8.3. Facilitate competition

Stakeholders have argued that any attempt to place cost on default service should be thwarted as the increased default service prices are simply a ploy to allow competitive service providers to compete more effectively on price. This argument is similarly flawed. The lack of allocation of costs is contrary to all rational business accounting practices, is contrary to NARUC guidance on cost allocation and allows utilities to maintain market power in the residential and small commercial customer segments. Incumbent utilities' default service market dominance has been maintained because the cost to serve default service customers is being subsidized inappropriately by distribution rates. No rational or prudent business would price products or services without a full and appropriate allocation of costs included.

Further, if the cost allocation is done correctly, every dollar allocated to default service is similarly deducted from distribution costs. In other words, it is a cost reallocation, not a cost increase. On net, default customers will pay no more for bundled energy (electrons and delivery) than they would pay prior to the reallocation of costs. The premise of competing against "higher rates" is simply a false premise.

8.4. Utility profitability

Some utilities have argued that there is no reason to allocate costs to the default service business because they do not earn a return on the provision of default service. Regardless of the validity of that statement, it is not a reason to justify an allocation approach. A properly run widget manufacturer should allocate costs to profitable and unprofitable lines of business. In the absence of such an allocation, the unprofitable line of business might be viewed as profitable, resulting in decisions that would cause further financial harm to the overall widget company (i.e., lowering the retail price on what are already unprofitable products). These irrational pricing decisions are the exact decisions that the default service utilities have been making (default service prices are too low and distribution rates are too high). If both services were truly competitive, the distribution would be run out of business by its lower-priced competitors and the underpriced default service "successes" would bankrupt the company. However, the utilities are protected from these irrational behaviors by virtue of the distribution monopoly.

The four primary arguments used to support the status quo are weak, at best. A cost allocation mechanism that keeps distribution companies whole as customers migrate on and off of default service could and should be implemented at all utilities that provide default service. The cost allocation implementation should include a comprehensive review of all utility costs inclusive of rate base assets, and all expenses, including executive salaries, legal departments, rate departments, customer service departments and all other employees and expenses. A measurable portion of those costs should be appropriately allocated to default service in accordance with NARUC guidelines and consistent with NARUC policies and objectives.

9. Conclusion

Default service pricing in the majority of the competitive retail energy markets is fundamentally flawed and allows the incumbent utilities to maintain a stronghold over their legacy customers in the residential and small commercial markets. Consistent with NARUC guidance, an appropriate amount of costs to serve default service customers should be allocated to default service rates. This is a critical next step in creating more competitively neutral retail energy markets in the US. This one step will not create the perfect market, but it will remove a significant pricing advantage held by incumbent utilities. It will also remove a subsidy that forces competitive supply customers to pay distribution rates that benefit default service customers, and it will help create a market in which competitive suppliers are more willing to invest. At the same time, if implemented correctly, it keeps distribution utilities financially whole. It is a win-win-win solution benefitting all market participants.

Frank Lacey President and Founding Principal Electric Advisors Consulting, LLC. Mr. Lacey is an experienced energy industry leader who has worked for advanced energy firms or consultancies for 25 years. He has been engaged in transforming the electricity industry throughout his career. His focus has been aligning business strategy with regulatory outcomes – interpreting rules and regulations and modifying strategies to align with those changes or seeking rule changes to align with strategies. Frank launched Electric Advisors Consulting, LLC in 2015. His mission is to help advanced energy companies develop strategies to integrate into existing markets or modify regulations so that the markets will accommodate advanced technologies and business plans.

FPL-5

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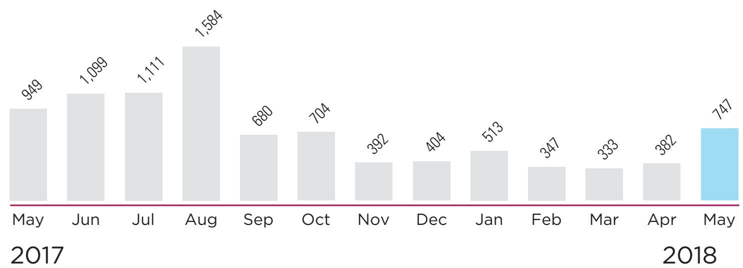

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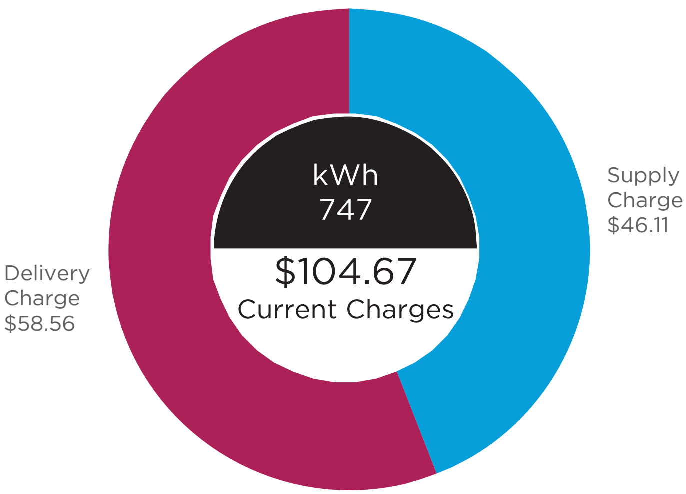

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Important Message

Bills may be paid by mail or to an authorized agent. Payment to others is at your own risk. For names and locations of authorized agents, please call us toll free at 1-800-807-6789. Customers who are hearing impaired may call 1-800-617-1234 (TDD/TTY).

We offer several ways for you to pay your bill. In addition to paying in person or by mail, you may receive and pay your bill electronically (e-Bill) or have your payments deducted automatically from your checking or savings account.

Definitions:

Actual: Reflects that a reading was taken from your meter.

Estimate: Reflects that we were unable to read your meter this month. We calculated your bill based on prior usage and seasonal variations. You can choose to call us with an actual meter read at 1-888-237-8811.

Kilowatt-hour (kWh): The unit measure for the electricity you use. For example, you use one kWh of electricity to light a 100-watt light bulb for 10 hours.

Customer Charge: The fixed monthly basic distribution charge to partially cover costs for billing, meter reading, service line maintenance and equipment.

Late Payment Charge: (If applicable) A late charge is added to the overdue amount of the regulated portion of your bill if you do not pay your bill by the due date.

Standard Service Offer: When customers purchase generation through AEP Ohio's auction process and not through a supplier.

Generation Service or Supply: Charges associated with the production of electricity.

Transmission Service: Charge for moving high-voltage electricity from a generation facility to the distribution station of the local electric utility. Transmission charges show under the delivery portion of the bill.

Distribution Service: Charge for use of local wires, transformers, substations and other equipment used to deliver electricity to your home/business. Distribution charges show under the delivery portion of the bill.

Retail Stability Rider (RSR): The RSR is necessary to provide AEP Ohio with stability while transitioning to 100% auction-based Standard Service Offering (generation service) pricing.

Phase-In Recovery Rider (PIRR): The PIRR will allow AEP Ohio to recover the cost of fuel deferred from 2009-2011 as previously authorized by the PUCO.

Deferred Asset Phase-In Rider (DAPIR): Recovers previously incurred deferrals for distribution assets.

Delivery: The graph on the first page shows charges associated with moving electricity through transmission lines and distribution lines as well as costs to maintain those lines and other distribution costs.

We welcome the opportunity to assist you. Our customer service center is open 24 hours a day, 7 days a week. If you have a question, please call us toll free at 1-800-672-2231, or 1-800-617-1234 (TDD/TTY). If you feel your concern has not been resolved, you can file a complaint at www.aepohio.com under "Contact Us", call 1-800-672-2231 or by writing to Customer Concerns, 4500 S. Hamilton Road, Groveport, OH 43125.

Customers may be assessed a deposit if they have not made a full payment (or arrangements) on a bill that contains a previous balance, or have been disconnected for nonpayment, fraudulent practice, tampering, or unauthorized reconnection during the preceding 12 months. Residential deposits may be made through a cash deposit or approved guarantor. Non-residential deposits may be made by cash, approved letters of credit, or approved surety bonds. To discuss any further options please call AEP Ohio. To contest a deposit you can file a complaint at www.aepohio.com under "Contact Us", call 1-800-672-2231 or by writing to Customer Concerns, 4500 S. Hamilton Road, Groveport, OH 43125.

If your complaint is not resolved after you have called AEP Ohio, or for general utility information, residential and business customers may contact the Public Utilities Commission of Ohio (PUCO) for assistance at 1-800-686-7826 (toll free) from 8 a.m. to 5 p.m. weekdays, or at www.PUCO.Ohio.gov. Hearing or speech impaired customers may contact the PUCO via 7-1-1 (Ohio relay service).

The Ohio Consumers' Counsel (OCC) represents utility customers in matters before the PUCO. The OCC can be contacted at 1-877-742-5622 from 8 a.m. to 5 p.m. weekdays, or at www.PickOCC.org.

Rates Available on Request

Electronic Check Conversion – if you pay by check, you authorize us to convert your paper check into an electronic debit.

If you have questions, please call AEP Ohio at 1-800-672-2231 or visit us at www.AEPOhio.com.

AEP OHIO

Service Address:

JANE SMITH

123 MAIN ST

ANY CITY, OH 43999-9999

Account #123-456-789-0-1

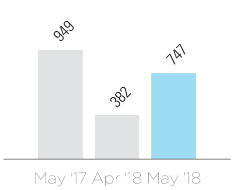
Line Item Charges:

Previous Charges		
Total Amount Due At Last Billing	$	59.31
Payment 05/04/18 - Thank You		-59.31
Previous Balance Due	**$**	**.00***
Current AEP Ohio Charges		
Tariff 013 - Residential Service 05/17/18 Service Delivery Identifier: 00000000000000000		
Generation Service (Supply)	$	44.23
Transmission Service		17.76
Distribution Service		30.68
Customer Charge		8.40
Retail Stability Rider		1.15
Deferred Asset Phase-In Rider		1.72
Power Purchase Agreement Rider		.73
Current Electric Charges	**$**	**104.67***
Total Balance Due *Charges make up the "Total Balance Due"	**$**	**104.67**

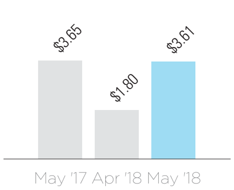
Usage Details:

Values reflect changes between current month and previous month.

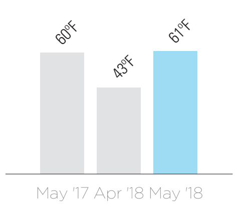
Usage:
365 kWh



Avg. Daily Cost:
$1.81



Avg. Temperature:
18 °F



Total usage for the past 12 months: 8,498 kWh

Average (Avg.) monthly usage: 708 kWh

Meter Read Details:

Meter #999999999					
Previous	Type	Current	Type	Metered	Usage
167	Actual	914	Actual	747	747 kWh
Service Period 04/18 - 05/17					Multiplier 1
Next scheduled read date should be between Jun 15 and Jun 20 .					

Notes from AEP Ohio:

Price-to-Compare: For **tariff 013,** in order for you to save money off of your utility's supply charges, a supplier must offer you a price lower than AEP Ohio's price of **$0.059** per kWh for the same usage that appears on this bill. To review available competitive supplier offers, visit the Public Utilities Commission of Ohio's "Energy Choice Ohio" web site at www.energychoice.ohio.gov.

For Informational Purposes only: The below costs are NOT NEW CHARGES and are approximate values. AEP participates in programs required by the state of Ohio to support energy conservation and to secure renewable energy resources. For more information on energy efficiency programs, please visit **aepohio.com/ItsYourPower**.

Renewable Programs: $0.73
Energy Efficiency Programs: $1.84
Peak Demand Reduction Programs: $0.70

Due date does not apply to previous balance due.

Register for online services at www.AEPOhio.com. Registration is **free and easy** and gives you the convenience of 24-hour access to your account. You can sign up for paperless billing, view your bill, check your usage, update your contact information, and much more.

AMERICAN ELECTRIC POWER

COST ALLOCATION MANUAL

As Of December 31, 2019

Corporate Accounting

AEP AMERICAN ELECTRIC POWER

The manual has been written to document AEP's approach to cost allocation and transfer pricing of affiliate transactions. Its purposes are to

- provide an easily referenced source of information
- state and clarify policy
- formalize procedures
- provide a basis of communication between all employees concerning cost allocation matters
- meet all regulatory requirements for maintaining a cost allocation manual.

The contents of the manual have been approved by management. Responsibility for adhering to the policies and procedures rests with every employee.

The manual is maintained in the A-Z index of AEP Now, under 'Cost Allocation Manual'. Maintenance of the documents incorporated in the manual by reference is the responsibility of the individuals and groups designated in the manual.

Errors in content and other requests for revision of this manual should be directed to the attention of Brian T. Lysiak.

Brian T. Lysiak
Senior Manager – Corporate Accounting

Jeffrey W. Hoersdig
Assistant Controller – Corporate Accounting

AMERICAN ELECTRIC POWER

CAM
Amendment Record

Rev. No.	Date Issued	Rev. No.	Date Issued	Rev. No.	Date Issued	Rev. No.	Date Issued
1	01-02-01	26	03-15-13	51		76	
2	10-22-01	27	08-31-13	52		77	
3	05-10-02	28	03-27-14	53		78	
4	10-18-02	29	09-15-14	54		79	
5	05-05-03	30	02-26-15	55		80	
6	08-29-03	31	09-15-15	56		81	
7	03-10-04	32	03-15-16	57		82	
8	08-27-04	33	09-15-16	58		83	
9	03-10-05	34	03-15-17	59		84	
10	08-30-05	35	09-15-17	60		85	
11	03-15-06	36	03-15-18	61		86	
12	08-31-06	37	08-31-18	62		87	
13	03-16-07	38	03-15-19	63		88	
14	09-24-07	39	09-15-19	64		89	
15	04-15-08	40	03-15-20	65		90	
16	09-25-08	41		66		91	
17	03-31-09	42		67		92	
18	07-13-09	43		68		93	
19	09-10-09	44		69		94	
20	03-31-10	45		70		95	
21	09-16-10	46		71		96	
22	03-25-11	47		72		97	
23	09-09-11	48		73		98	
24	03-14-12	49		74		99	
25	09-14-12	50		75		100	

Cost Allocation Manual

Section

Controls

Subject

TABLE OF CONTENTS

This table of contents is intended to give a cover-to-cover overview of the contents and organization of the AEP Cost Allocation Manual (CAM). See HOW TO USE THIS MANUAL (00-00-02) for an explanation of the numbering system.

Cost Allocation Manual

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Cost Allocation Manual

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OVERVIEW

SUMMARY	AEP’s internal guidelines applicable to cost allocations are designed to result in a fair and equitable allocation of costs. Policies and procedures have also been formulated to meet regulatory standards both for cost allocation and affiliate transactions.
COST ALLOCATION POLICIES AND PROCEDURES	Each AEP subsidiary maintains separate books and records. Transactions are coded and processed in a manner that meets all regulatory requirements. Proper audit trails are maintained so that costs can be traced from source documents all the way through the applicable accounting and billing systems.
	02-02-02
THE COST ALLOCATION PROCESS	Unless otherwise exempted, the AEP companies allocate costs between regulated and non-regulated operations, on a fully-distributed cost basis. Fully-distributed costs include all direct costs plus an appropriate share of indirect costs.
	02-02-03
COST POOLING AND COST ASSIGNMENT	Indirect costs are pooled and assigned to multiple companies or company segments in accordance with the relative benefits received or by other equitable means.
	02-02-04
ACCOUNT DESIGNATIONS	The operation and maintenance expense accounts in the Federal Energy Regulatory Commission’s (FERC’s) uniform system of accounts break functionally between regulated and non-regulated expenses. Certain administrative and general expenses
ACCOUNT DESIGNATIONS	include costs that can be attributed to

Cont'd)

both regulated and non-regulated activities. Some of AEP's generation has been restructured as a competitive activity, and therefore, the power production accounts in the FERC's system of accounts become non—regulated accounts.

02-02-05

AMERICAN ELECTRIC POWER

Document Number **02-02-02**

Cost Allocation Manual

Section

Corporate

Subject

COST ALLOCATION POLICIES AND PROCEDURES

SUMMARY

Cost allocation is the process of assigning a single cost to one or more company or company segments on the basis of the relative benefits received or other equitable basis. This document summarizes the underlying cost allocation policies and procedures that are applied on a corporate-wide basis by all AEP companies.

POLICIES AND PROCEDURES

AEP's cost accounting and cost allocation policies and procedures shall not result in any cost subsidies among or between regulated and non-regulated operations. Unless otherwise exempted, all affiliate transactions for services or products will be conducted at fully allocated cost. For the transfer of capital assets, fully allocated cost shall equal the net book value of the capital asset.

The term "affiliate transactions" refers to all transactions between the utility and any separate affiliate company, both regulated and non-regulated, including all transactions between a utility's regulated operations (above-the-line) and non-regulated operations (below-the-line).

Basic Goal

The basic goal of AEP's cost allocation policies and procedures are threefold:

- to ensure a fair and equitable distribution of costs among all benefiting parties
- to meet pertinent regulatory requirements
- to minimize the time and expense needed to record, audit and report transactions.

OHIO POWER COMPANY'S RESPONSE
TO INTERSTATE GAS SUPPLY
DISCOVERY REQUESTS
PUCO CASE 20-585-EL-AIR
FIFTH SET

INTERROGATORY

IGS-INT-05-001 Please identify the amount of revenue that AEP Ohio has collected from customers during the test year for distribution, transmission, and generation services.

RESPONSE

See IGS-INT-5-001 Attachment 1 for billed retail revenues by function. The company does not track collections by function.

Prepared by:

Jason M. Yoder

FPL-7

Revn Yr/Mo	Rev Line Of Bsns	Sales of ELE Amt
202003	D	105,422,672.63
202003	T	39,811,987.11
202004		0
202009	G	44,820,005.94
202001		0
202005	B	0
202009		0
202002	D	106,235,639.73
202005	T	51,910,724.82
202006	B	0
202010	B	0
201912	D	104,644,490.8
202010	T	54,386,530.48
202008	T	69,698,206.99
202003	A	0
202006		0
202004	B	0
202008		0
202004	D	96,870,205.09
202006	G	39,396,211.39
202005	G	37,635,134.77
202007		0
202007	B	0
202009	D	117,625,087.05
202006	A	0
202003	G	51,454,013.65
202008	D	123,710,584.21
201912	A	0
202001	T	45,347,780.35
202009	T	64,893,231.58
202007	A	0
202005	D	94,138,705.7

Sum of Sales of ELE Amt	**Column Labels**			
Row Labels	**D**	**G**	**T**	**Grand Total**
201912	104,644,490.80	59,437,769.01	44,761,791.11	208,844,050.92
202001	114,086,740.43	58,488,050.50	45,347,780.35	217,922,571.28
202002	106,235,639.73	52,451,070.79	44,504,938.87	203,191,649.39
202003	105,422,672.63	51,454,013.65	39,811,987.11	196,688,673.39
202004	96,870,205.09	38,475,219.52	54,402,022.87	189,747,447.48
202005	94,138,705.70	37,635,134.77	51,910,724.82	183,684,565.29
202006	99,941,479.65	39,396,211.39	59,497,018.33	198,834,709.37
202007	120,899,870.33	48,342,592.50	68,954,688.56	238,197,151.39
202008	123,710,584.21	49,781,517.64	69,698,206.99	243,190,308.84
202009	117,625,087.05	44,820,005.94	64,893,231.58	227,338,324.57
202010	100,214,195.00	34,583,590.94	54,386,530.48	189,184,316.42
202011	97,348,175.46	35,150,364.28	51,962,486.23	184,461,025.97
Grand Total	**1,281,137,846.08**	**550,015,540.93**	**650,131,407.30**	**2,481,284,794.31**

FPL-7

202008	G	49,781,517.64
202006	D	99,941,479.65
202001	B	0
201912	T	44,761,791.11
202003		0
202010		0
202006	T	59,497,018.33
202005		0
202011	B	0
202002		0
202008	B	0
202007	G	48,342,592.5
202001	A	0
202002	A	0
202011	T	51,962,486.23
202008	A	0
202002	B	0
202011	A	0
202010	D	100,214,195
202004	T	54,402,022.87
202007	D	120,899,870.33
202009	A	0
202010	G	34,583,590.94
202010	A	0
201912	B	0
202001	D	114,086,740.43
202007	T	68,954,688.56
202011		-24.87
201912		0
202009	B	0
202003	B	0
202011	D	97,348,175.46
201912	G	59,437,769.01

202011	G	35,150,364.28
202002	T	44,504,938.87
202004	A	0
202004	G	38,475,219.52
202005	A	0
202002	G	52,451,070.79
202001	G	58,488,050.5

OHIO POWER COMPANY'S RESPONSE TO
INTERSTATE GAS SUPPLY, INC.'S
DISCOVERY REQUEST
PUCO CASE 20-585-EL-AIR
THIRD SET

INTERROGATORY

IGS-INT-03-025 Please identify the total amount of revenue that AEP Ohio collected from customers (distribution, transmission, and SSO generation) during the following time periods:
a. 2018
b. 2019
c. 2020

RESPONSE

Please see IGS-INT-03-025 Attachment 1.xlsx for the requested information for 2018, 2019 and year-to-date 2020.

Prepared by:

David M. Roush

Billed Sales of Electricity $ by Function

Source: Company's Billing Records

Time Period	Generation	Transmission	Distribution	Total
Calendar 2018	961,714,123	660,147,159	1,300,600,309	2,922,461,592
Calendar 2019	730,049,397	550,918,974	1,198,985,892	2,479,954,263
January through August 2020	376,023,811	434,127,368	861,305,898	1,671,457,076

OHIO POWER COMPANY'S RESPONSE TO
INTERSTATE GAS SUPPLY, INC.'S
DISCOVERY REQUEST
PUCO CASE 20-585-EL-AIR
THIRD SET

INTERROGATORY

IGS-INT-03-012 As of December 31, 2019, please identify the total number of AEP Ohio distribution customers in each of the following customer classes, breaking out shopping vs. non-shopping for each category:
a. Residential
b. Commercial
c. Industrial
d. Area & Street Lighting
e. Schools
f. County & Independent Fairs

RESPONSE

See IGS-INT-03-12 Attachment 1 for the requested information.

Prepared by:

David M. Roush

Monthly Customers by Tariff

Sum - Cust	Shopping	
Tariff Rollup	Non-Shop	Shop
Residential	839,793	461,784
GS-1/FL	63,095	60,775
GS-2/3/EHG	19,790	44,746
GS-4	5	82
Lighting	463	743
School	303	2,237
Fair	57	104
Total Result	**923,506**	**570,471**

OHIO POWER COMPANY'S RESPONSE TO
DIRECT ENERGY SERVICES LLC's
DISCOVERY REQUEST
PUCO CASE 20-585-EL-AIR
FIRST SET

INTERROGATORY

Direct-INT-01-001 For each of the calendar years 2012 through 2020, Identify:
a. The total dollar amount of Registration Fees paid to the Company
b. The total dollar amount of Renewal Fees paid to the Company
c. The total dollar amount of Customer List Fees paid to the Company
d. The total dollar amount of Interval Data Fees paid to the Company
e. The total dollar amount of Switching paid to the Company
f. The total dollar amount of EFYW Fees paid to the Company
g. The total dollar amount of all other fees paid to the Company by CRES Providers.

RESPONSE

See Direct-INT-01-001 Attachment 1

Prepared by:

Andrea E. Moore

Ref.	Fee	2012	2013	2014	2015	2016	2017	2018	2019	2020**	Total
a	**Registration Fees**	N/A	N/A	1,000.00	3,600.00	3,900.00	3,400.00	600.00	2,000.00	900.00	**15,400.00**
b	**Renewal Fees**	N/A	N/A	N/A	N/A	3,200.00	400.00	100.00	9,600.00	13,500.00	**26,800.00**
c	**Pre-enrollment Customer List Fees**	N/A	N/A	N/A	4,200.00	1,050.00	1,200.00	300.00	0.00	0.00	**6,750.00**
d	**Interval Data Fees***	N/A	N/A	60,146.00	13,558.00	6,266.00	6,900.00	4,750.00	5,350.00	1,100.00	**98,070.00**
e	**Provider Switch Fees**	N/A	N/A	406,880.00	532,330.00	405,300.00	488,990.00	567,770.00	611,765.00	451,410.00	**3,464,445.00**
f	**Enroll From Your Wallet (EFYW) Fees**	N/A	N/A	N/A	N/A	N/A	N/A	N/A	20,000.00	5,000.00	**25,000.00**
g	**All Other Fees**										
	Supplier Consolidated Billing Pilot Program Development Fees	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1,000,000.00	N/A	**1,000,000.00**
	TOTAL ALL FEES										**4,636,465.00**

* Interval Data Fees included here are for Suppliers and Brokers related to Customer Choice only.
** 2020 data is as of second week of Dec. 2020.

OHIO POWER COMPANY'S RESPONSE TO
INTERSTATE GAS SUPPLY, INC.'S
DISCOVERY REQUEST
PUCO CASE 20-585-EL-AIR
FOURTH SET

INTERROGATORY

IGS-INT-04-009 Regarding the document attached labeled Attachment B:
a. Please identify the costs associated with creating, printing, and disseminating Attachment B including labor.
b. Please identify whether salaries related to individuals that developed the document included in Attachment B are reflected in the test year expense.
c. Please identify the recovery mechanism(s) for costs identified in response to (a).
d. Are any costs associated with creating, printing, and disseminating Attachment B included in the test year?
e. Please identify the AEP Ohio customers that received a copy of Attachment B.
f. How were the customers identified in (e) determined?
g. In identifying the customers in (e), what information and/or data regarding the customer did AEP Ohio consider (i.e. rate class, annual usage, hourly usage, demand, etc.)?
h. Please identify how AEP Ohio obtained addresses and personal information regarding any individuals identified in response to (e).
i. Please identify the approximate date range that AEP Ohio provided Attachment B to customers.

RESPONSE

a. The Company did not separately identify the costs associated with the internal development of Attachment B.
b. This type of cost would be included to the extent these employees billed their time to work orders that are funded by AEP Ohio during the test year. However, the letter was developed and intended for use prior to the beginning of the test year (September-October 2019), therefore, employee salaries related to the development of Attachment B are not included in the test year expense.
c. This type of cost is not encompassed by any rider and is generally reflected in base rates.
d. See the response to IGS-INT-04-009.b.
e. The Company objects to this request as seeking information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection(s) or any general objection the Company may have, the Company states as follows. The Company's customer account representatives provided Attachment B to AEP Ohio commercial and industrial customers with whom we have familiarity of their service needs as part of our customer account relationships.

**OHIO POWER COMPANY'S RESPONSE TO
INTERSTATE GAS SUPPLY, INC.'S
DISCOVERY REQUEST
PUCO CASE 20-585-EL-AIR
FOURTH SET**

f. See the response to IGS-INT-04-009.e.
g. See the response to IGS-INT-04-009.e.
h. See the response to IGS-INT-04-009.e.
i. See the response to IGS-INT-04-009.b.

Prepared by:

Counsel

Jon F. Williams

Andrea E. Moore

OHIO POWER COMPANY'S RESPONSE TO
INTERSTATE GAS SUPPLY'S
DISCOVERY REQUEST
PUCO CASE 20-585-EL-AIR
SIXTH SET

INTERROGATORY

IGS-INT-06-004 Regarding customer sited renewable energy resources that may be constructed under R.C. 4928.47:
a. Has AEP Ohio solicited any customers for this purpose?
b. If the answer to (a) is yes, identify how AEP Ohio determined which customers to solicit.
c. If the answer to (a) is yes, how did AEP Ohio track the direct and indirect costs associated with these solicitations?
d. If the answer to (a) is yes, how were such costs removed from the test year?

RESPONSE

a.-d. The Company objects to this request as seeking information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection(s) or any general objection the Company may have, the Company states as follows. The Company has had preliminary conversations with interested customers in the context of traditional customer service about providing potential renewable solutions to meet their needs. Any costs associated with such conversations are incidental to the utility's customer service function and do not constitute project costs. See the Company's response to IGS-INT-06-004 for project cost tracking information.

Prepared by:

Jon F. Williams

Guidelines for Cost Allocations and Affiliate Transactions:

The following Guidelines for Cost Allocations and Affiliate Transactions (Guidelines) are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates. The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. They are intended to provide a framework for regulated entities and regulatory authorities in the development of their own policies and procedures for cost allocations and affiliated transactions. Variation in regulatory environment may justify different cost allocation methods than those embodied in the Guidelines.

The Guidelines acknowledge and reference the use of several different practices and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight. The implementation and compliance with these cost allocations and affiliate transaction guidelines, by regulated utilities under the authority of jurisdictional regulatory commissions, is subject to Federal and state law. Each state or Federal regulatory commission may have unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing standards. For example, The Public Utility Holding Company Act of 1935 requires registered holding company systems to price "at cost" the sale of goods and services and the undertaking of construction contracts between affiliate companies.

The Guidelines were developed by the NARUC Staff Subcommittee on Accounts in compliance with the Resolution passed on March 3, 1998 entitled "Resolution Regarding Cost Allocation for the Energy Industry" which directed the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations." In addition, input was requested from other industry parties. Various levels of input were obtained in the development of the Guidelines from the Edison Electric Institute, American Gas Association, Securities and Exchange Commission, the Federal Energy Regulatory Commission, Rural Utilities Service and the National Rural Electric Cooperatives Association as well as staff of various state public utility commissions.

In some instances, non-structural safeguards as contained in these guidelines may not be sufficient to prevent market power problems in strategic markets such as the generation market. Problems arise when a firm has the ability to raise prices above market for a sustained period and/or impede output of a product or service. Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates. Consideration should be given to any "unique" advantages an incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions.

A. DEFINITIONS

1. Affiliates - companies that are related to each other due to common ownership or control.

2. Attestation Engagement - one in which a certified public accountant who is in the practice of public accounting is contracted to issue a written communication that expresses a conclusion about the reliability of a written assertion that is the responsibility of another party.

3. Cost Allocation Manual (CAM) - an indexed compilation and documentation of a company's cost allocation policies and related procedures.

4. Cost Allocations - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

5. Common Costs - costs associated with services or products that are of joint benefit between regulated and non-regulated business units.

6. Cost Driver - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. Direct Costs - costs which can be specifically identified with a particular service or product.

8. Fully Allocated costs - the sum of the direct costs plus an appropriate share of indirect costs.

9. Incremental pricing - pricing services or products on a basis of only the additional costs added by their operations while one or more pre-existing services or products support the fixed costs.

10. Indirect Costs - costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.

11. Non-regulated - that which is not subject to regulation by regulatory authorities.

12. Prevailing Market Pricing - a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

13. Regulated - that which is subject to regulation by regulatory authorities.

14. Subsidization - the recovery of costs from one class of customers or business unit that are attributable to another.

B. COST ALLOCATION PRINCIPLES

The following allocation principles should be used whenever products or services are provided between a regulated utility and its non-regulated affiliate or division.

1. To the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided.

2. The general method for charging indirect costs should be on a fully allocated cost basis. Under appropriate circumstances, regulatory authorities may consider incremental cost, prevailing market pricing or other methods for allocating costs and pricing transactions among affiliates.

3. To the extent possible, all direct and allocated costs between regulated and non-regulated services and products should be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. Documentation should be made available to the appropriate regulatory authority upon request regarding transactions between the regulated utility and its affiliates.

4. The allocation methods should apply to the regulated entity's affiliates in order to prevent

subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa.

5. All costs should be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

6. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.

7. The indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.

C. COST ALLOCATION MANUAL (NOT TARIFFED)

Each entity that provides both regulated and non-regulated services or products should maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. The determination of what, if any, information should be held confidential should be based on the statutes and rules of the regulatory agency that requires the information. Any entity required to provide notification of a CAM(s) should make arrangements as necessary and appropriate to ensure competitively sensitive information derived therefrom be kept confidential by the regulator. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company, depicting all affiliates, and regulated entities.

2. A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.

3. A description of all assets, services and products provided by the regulated entity to non-affiliates.

4. A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

D. AFFILIATE TRANSACTIONS (NOT TARIFFED)

The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization. However, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged.

The objective of the affiliate transactions' guidelines is to lessen the possibility of subsidization in order to protect monopoly ratepayers and to help establish and preserve competition in the electric generation and the electric and gas supply markets. It provides ample flexibility to accommodate exceptions where the outcome is in the best interest of the utility, its ratepayers and competition. As with any transactions, the burden of proof for any exception from the general rule rests with the proponent of the exception.

1. Generally, the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation.

E. AUDIT REQUIREMENTS

1. An audit trail should exist with respect to all transactions between the regulated entity and its affiliates that relate to regulated services and products. The regulator should have complete access to all affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with the guidelines. Regulators should have complete access to affiliate records, consistent with state statutes, to ensure that the regulator has access to all relevant information necessary to evaluate whether subsidization exists. The auditors, not the audited utilities, should determine what information is relevant for a particular audit objective. Limitations on access would compromise the audit process and impair audit independence.

2. Each regulated entity's cost allocation documentation should be made available to the company's internal auditors for periodic review of the allocation policy and process and to any jurisdictional regulatory authority when appropriate and upon request.

3. Any jurisdictional regulatory authority may request an independent attestation engagement of the CAM. The cost of any independent attestation engagement associated with the CAM, should be shared between regulated and non-regulated operations consistent with the allocation of similar common costs.

4. Any audit of the CAM should not otherwise limit or restrict the authority of state regulatory authorities to have access to the books and records of and audit the operations of jurisdictional utilities.

5. Any entity required to provide access to its books and records should make arrangements as necessary and appropriate to ensure that competitively sensitive information derived therefrom be kept confidential by the regulator.

F. REPORTING REQUIREMENTS

1. The regulated entity should report annually the dollar amount of non-tariffed transactions

associated with the provision of each service or product and the use or sale of each asset for the following:

a. Those provided to each non-regulated affiliate.

b. Those received from each non-regulated affiliate.

c. Those provided to non-affiliated entities.

2. Any additional information needed to assure compliance with these Guidelines, such as cost of service data necessary to evaluate subsidization issues, should be provided.

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

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$25.00

CONTENTS

CHAPTER 2

OVERVIEW OF COST OF SERVICE STUDIES AND COST ALLOCATION

This chapter presents an overview of cost of service studies and cost allocation theory. It first introduces the role of cost of service studies in the regulatory process. Next, it summarizes the theory and methodologies of cost studies, with a comparison of accounting-based (embedded) cost methodologies and marginal cost methodologies. Finally, it introduces and briefly discusses the three major steps in the cost allocation process: the "functionalization" of investments and expenses, cost "classification" , and the "allocation" of costs among customer classes.

I. COST OF SERVICE STUDIES IN THE REGULATORY PROCESS

Cost of service studies are among the basic tools of ratemaking. While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates.

The cost principle applies not only to the overall level of rates, but to the rates set for individual services, classes of customers, and segments of the utility's business. Cost studies are therefore used by regulators for the following purposes:

- To attribute costs to different categories of customers based on how those customers cause costs to be incurred.
- To determine how costs will be recovered from customers within each customer class.
- To calculate costs of individual types of service based on the costs each service requires the utility to expend.
- To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets.

- To separate costs between different regulatory jurisdictions.

Generically, the prime purpose of cost of service studies is to aid in the design of rates. The development of rates for a utility may be divided into four basic steps:

- Development of the test period total utility revenue requirement - The total revenue requirement is the level of revenue to be collected from all sources. This subject will be addressed in detail in Chapter 3.

- Calculation of the test period revenue requirement to be recovered through rates - This is simply the total revenue requirement of the utility from all sources less the amount from sources other than rates.

- The cost allocation procedure - The total revenue requirement of the utility is attributed to the various classes of customers in a fashion that reflects the cost of providing utility services to each class. The cost allocation process consists of three major parts: functionalization of costs, classification of costs, and allocation of costs among customer classes.

- Design of rates - Regulators design rates, the prices charged to customer classes, using the costs incurred by each class as a major determinant. Other non-cost attributes considered by regulators in designing rates include revenue-related considerations of effectiveness in yielding total revenue requirements, revenue stability for the company and rate continuity for the customer, as well as such practical criteria as simplicity and public acceptance.

II. THEORY AND METHODOLOGIES

Historically, regulation concerned itself with the overall level of a company's revenues and earnings and left the design of rates to the discretion of the utility. To the extent that utility managements justified their rate structures on cost, rather than rationales of value of service or "what the market will bear", they defined cost in engineering and accounting terms. Utilities developed cost studies that were based on monies actually spent (embedded) for plant and operating expenses and divided those costs (fully allocated or distributed them) among the classes of customers according to principles of cost causation. The task for the analyst was to allocate, among customers, the costs identified in the test year for which the revenue requirement had been calculated.

Through the years, the industry and its regulators have witnessed a gradual evolution of the concepts for allocation. Since generating units and transmission lines are sized according to the peak demand consumed, the individual contribution to peak demand came to be considered the appropriate factor for the allocation of the costs of those

FPL-15


AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY
Leading the Way Forward
54th EEI Financial Conference
Orlando, Florida
November 10-12, 2019

"Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Although AEP and each of its Registrant Subsidiaries believe that their expectations are based on reasonable assumptions, any such statements may be influenced by factors that could cause actual outcomes and results to be materially different from those projected. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are: changes in economic conditions, electric market demand and demographic patterns in AEP service territories, inflationary or deflationary interest rate trends, volatility in the financial markets, particularly developments affecting the availability or cost of capital to finance new capital projects and refinance existing debt, the availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material, decreased demand for electricity, weather conditions, including storms and drought conditions, and the ability to recover significant storm restoration costs, the cost of fuel and its transportation, the creditworthiness and performance of fuel suppliers and transporters and the cost of storing and disposing of used fuel, including coal ash and spent nuclear fuel, the availability of fuel and necessary generation capacity and performance of generation plants, the ability to recover fuel and other energy costs through regulated or competitive electric rates, the ability to build or acquire renewable generation, transmission lines and facilities (including the ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs, new legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances that could impact the continued operation, cost recovery and/or profitability of generation plants and related assets, evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including coal ash and nuclear fuel, timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance, resolution of litigation, the ability to constrain operation and maintenance costs, prices and demand for power generated and sold at wholesale, changes in technology, particularly with respect to energy storage and new, developing, alternative or distributed sources of generation, the ability to recover through rates any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives, volatility and changes in markets for coal and other energy-related commodities, particularly changes in the price of natural gas, changes in utility regulation and the allocation of costs within regional transmission organizations, including ERCOT, PJM and SPP, changes in the creditworthiness of the counterparties with contractual arrangements, including participants in the energy trading market, actions of rating agencies, including changes in the ratings of debt, the impact of volatility in the capital markets on the value of the investments held by the pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact of such volatility on future funding requirements, accounting standards periodically issued by accounting standard-setting bodies, and other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, naturally occurring and human-caused fires, cyber security threats and other catastrophic events, the ability to attract and retain requisite work force and key personnel.

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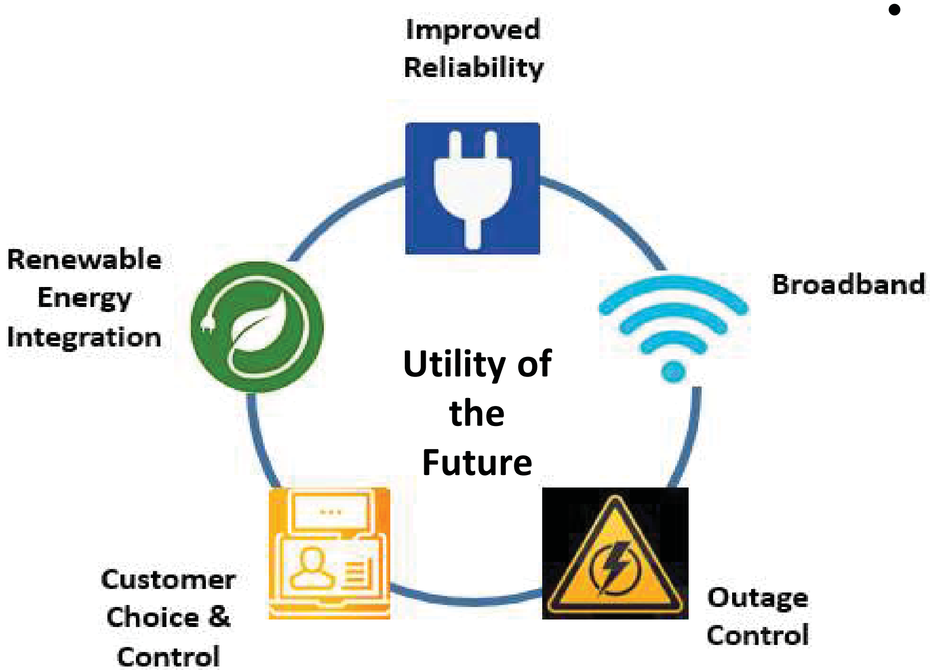
UTILITY TRANSFORMATION

Expanded Core and Future Investments

- Increase core investments in system reliability
- Fully advance metering infrastructure (AMI) and distribution automation circuit reconfiguration (DACR) penetration
- LED Street Light Modernization

- Promote an interactive, modern and efficient grid
- Adapt grid to integrate more diverse energy sources
- Broadband and behind the meter technologies to align with changing customer expectations
- Advance electrification



Positioning to align future investments with customer preferences

Advancing policies and regulatory mechanisms that support timely recovery and diversification of investments

Asset Renewal + **Grid Modernization** + **New Product Lines** = **Distribution Investment Opportunity**

Identified Core Business Investments

Improve Reliability → Grow and Diversify the Business → Maintaining Strong Balance Sheet

Current State of Distribution Grid

- $1.8B of annual investment
- **$2.7B** investment needed to maintain current assets

10-Year Incremental Distribution Capital Investment Potential: ~$18B[1]

AEP invests in our customers' future by focusing on reliability and the customer experience.
AEP has a strong track record in securing regulatory support and executing distribution investments.

Investment Opportunity	Capital Investment $
Grid Modernization	$2.4 billion
Line Re-conductoring – Asset Renewal	$13.0 billion
Pole Replacements – Asset Renewal	$0.5 billion
Distribution Station Transformer and Breaker Replacements – Asset Renewal	$1.4 billion

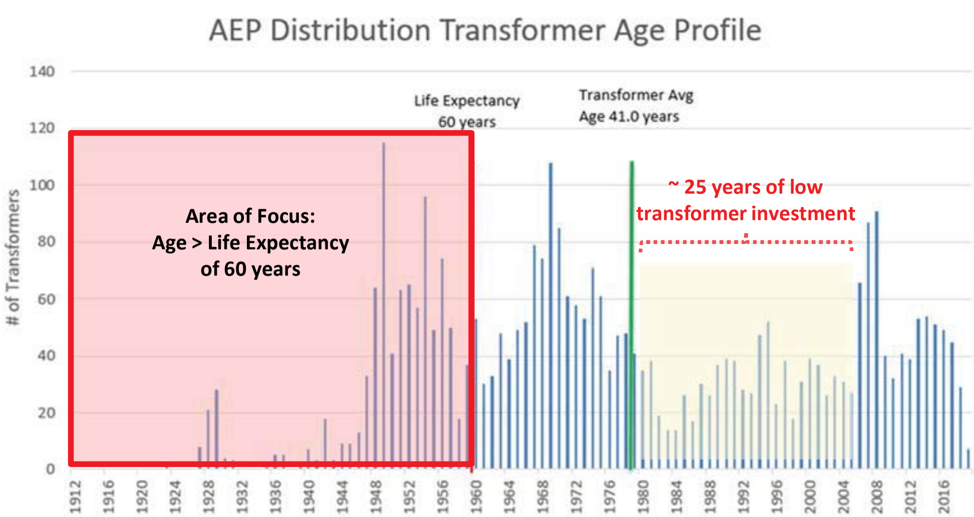
Known and identified investments that will improve reliability and operability of the grid

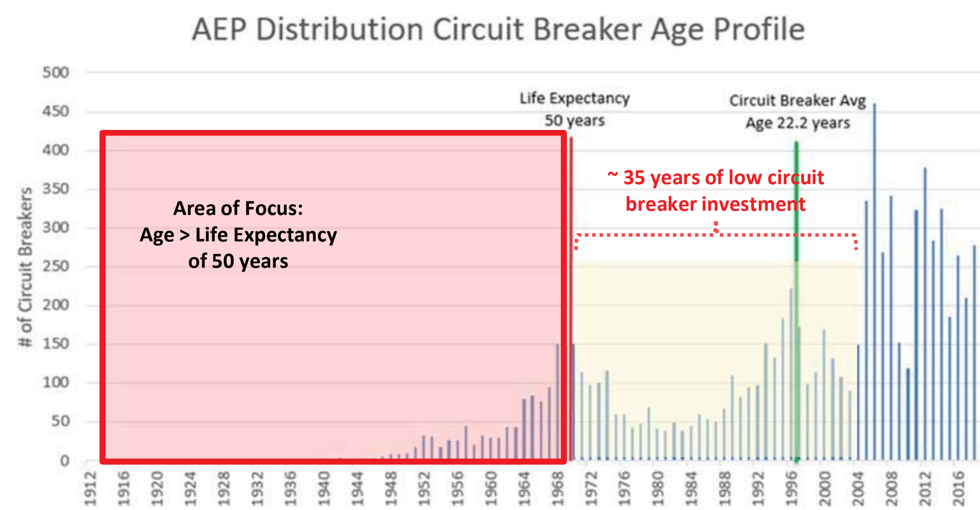
Partner with states to help spur economic development

[1] 10-year capital investment potential is above current $1.8B annual spend, 7-10% O&M required to support the capital investment

Robust Distribution Capital Expenditure Opportunities

Type	Life Expectancy	Current Quantity over Life Expectancy	Quantity that will Exceed Life Expectancy in Next 10 Years	Total Replacement Need	Percent of AEP System Total
Transformers	60	903	565	1,468	41%
Circuit Breakers	50	1,030	842	1,872	21%





$2.7 billion of annual on-system capital investment is required to maintain current age profile

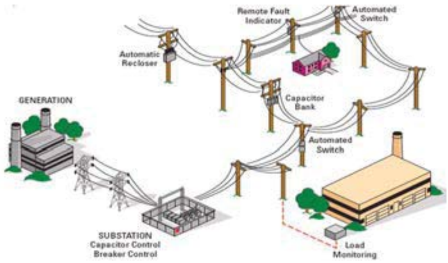
New Legislative Initiatives

- **Ohio Bilateral Contracts Bill (HB6)**
  - Recovery of existing renewable contracts entered into to comply with existing legislation
  - Recovery of OVEC collected on a state-wide basis until 2030
  - Provides opportunity for AEP Ohio to enter into bilateral contracts with certain customers
  - Provides $20 million of clean air funds for approved solar projects, including 400MW at AEP
- **Ohio Smart Grid Bill (HB247)** – Would allow for inclusion of smart grid technologies in electric security plans and allows AEP Ohio to pursue behind the meter technologies
- **Ohio Broadband Deployment (HB13)** – Promotes broadband investment through establishment of residential broadband expansion program
- **Indiana TDSIC Bill** - Broadens definition of grid improvements included in energy delivery tracker
- **West Virginia Broadband (SB3)** – Promotes broadband investment
- **Virginia Broadband (HB2691)** – Establishes pilot program for broadband capacity to unserved areas
- **Oklahoma EV Bill** – Extends tax credits for EV infrastructure
- **Texas Generation Rider** – Recovery of new power generation facilities outside ERCOT
- **Texas AMI Bill** – Adds recovery of advanced meter deployment outside ERCOT

Technology and Innovation

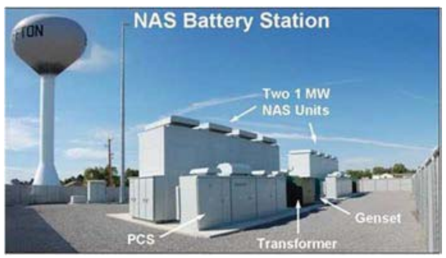
Innovative Reliability and Operation

Remote Line Sensors



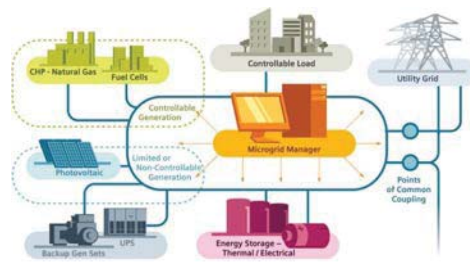
Distribution Automation

ADMS



Energy Storage

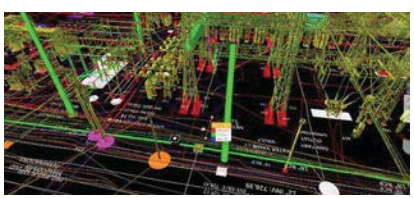
Fault Interruption Technology



Microgrids

- Reliability-focused Innovation
- Customer Experience
- Operational Visibility
- Economic Operation
- Enhances Safety

Engineering Innovation



LIDAR

Drones

Augmented Reality

- Design Excellence
- Reduced Labor
- Rapid Engineering
- Digitized Platforms

Ohio Power Company Rate Increase Request
PUCO Case No. 20-585-EL-AIR
Allocation of Costs to SSO

Allocation Factors	
R	22.17%
C	38.18%
A	100.00%

Label	Total Retail	RS: Residential	GS: Non-Demand Metered	GS: Demand Metered - SEC	GS: Demand Metered - PRI	GS: Demand Metered - SUB/TRAN	Total GS - DM	OL: Outdoor Lighting	SL: Street Lighting	Allocator	Allocation to SSO
	1	2	3	4	5	6	7	8	9		
Rate Base											
Plant in Service											
Distribution											
360 Land and Land Rights	-	-	-	-	-	-	-	-	-	R	-
361 Structures and Improvements	-	-	-	-	-	-	-	-	-	R	-
362 Station Equipment	-	-	-	-	-	-	-	-	-	R	-
363 Storage Battery Equipment	-	-	-	-	-	-	-	-	-	R	-
364 Poles, Towers & Fixtures	-	-	-	-	-	-	-	-	-	R	-
365 Overhead Lines	-	-	-	-	-	-	-	-	-	R	-
366 Underground Conduit	-	-	-	-	-	-	-	-	-	R	-
367 Underground Lines	-	-	-	-	-	-	-	-	-	R	-
368 Transformers	-	-	-	-	-	-	-	-	-	R	-
369 Services	-	-	-	-	-	-	-	-	-	R	-
370 Meters	-	-	-	-	-	-	-	-	-	R	-
371 Install on Cust. Premises	-	-	-	-	-	-	-	-	-	R	-
372 Leased Prop. On Cust. Premises	-	-	-	-	-	-	-	-	-	R	-
373 Street Lighting	-	-	-	-	-	-	-	-	-	R	-
Total	-	-	-	-	-	-	-	-	-	R	-
Reduction Factor										R	-
Distribution Additions Through 8/31/2014	-	-	-	-	-	-	-	-	-	R	-
							-			R	-
Total Plant in Service	-	-	-	-	-	-	-	-	-	R	-
General Plant	114,727,617	79,801,470	6,214,633	6,028,635	10,109,551	7,152,421	23,290,607	4,131,131	1,289,777	R	25,431,169
Intangible Plant	-	-	-	-	-	-	-	-	-	R	-
Total General & Intangible Plant	114,727,617	79,801,470	6,214,633	6,028,635	10,109,551	7,152,421	23,290,607	4,131,131	1,289,777	R	25,431,169
Total Electric Plant in Service	114,727,617	79,801,470	6,214,633	6,028,635	10,109,551	7,152,421	23,290,607	4,131,131	1,289,777	R	25,431,169
Electric Plant Acquisition Adj. - Account 302	169,528	117,919	9,183	8,908	14,938	10,569	34,415	6,104	1,906	R	37,578
Electric Utility Plant	114,897,145	79,919,388	6,223,816	6,037,543	10,124,489	7,162,989	23,325,022	4,137,235	1,291,683	R	25,468,747
Ratio of Intangible Plant											
Accum. Depreciation and Amortiz.											
Distribution	-	-	-	-	-	-	-	-	-	R	-
General & Intangible	(32,134,560)	(23,460,455)	(1,827,010)	(1,772,330)	(2,972,059)	(2,102,706)	(6,847,095)	-	-	R	(7,123,127)
Total	(32,134,560)	(23,460,455)	(1,827,010)	(1,772,330)	(2,972,059)	(2,102,706)	(6,847,095)	-	-	R	(7,123,127)
										R	-
Amortiz. Of Plant Acquisition Adj. - Acct 302	(161,517)	(117,919)	(9,183)	(8,908)	(14,938)	(10,569)	(34,415)	-	-	R	(35,803)
Net Electric Plant in Service	82,601,068	56,341,015	4,387,623	4,256,305	7,137,492	5,049,715	16,443,512	4,137,235	1,291,683	R	18,309,817
Construction Work In Progress										R	-
Distribution	-	-	-	-	-	-	-	-	-	R	-
General	-	-	-	-	-	-	-	-	-	R	-
Total	-	-	-	-	-	-	-	-	-	R	-
Working Capital											
Uncollectibles	-	-	-	-	-	-	-	-	-	R	-
Materials & Supplies - Dist	283,102	150,093	15,955	13,131	25,153	20,034	58,318	37,383	21,353	R	62,754
Prepayments - Other (Insurance, etc.)	1,564,549	886,803	87,414	74,704	138,756	107,797	321,256	173,312	95,763	R	346,807
Other Current Assets	-	-	-	-	-	-	-	-	-	R	-
Total Working Capital	1,847,651	1,036,896	103,368	87,835	163,909	127,831	379,575	210,696	117,117		409,561

Ohio Power Company Rate Increase Request
PUCO Case No. 20-585-EL-AIR
Allocation of Costs to SSO

Label	Total Retail	RS: Residential	GS: Non-Demand Metered	GS: Demand Metered - SEC	GS: Demand Metered - PRI	GS: Demand Metered - SUB/TRAN		Total GS - DM	OL: Outdoor Lighting	SL: Street Lighting	Allocator	Allocation to SSO
	1	2	3	4	5	6	7		8	9		
												-
Rate Base Offsets											R	-
Customer Deposits	(55,112,146)	(35,737,340)	(2,087,958)	(12,779,763)	(3,307,877)	(1,148,029)		(17,235,669)	(51,179)	-	R	(12,216,468)
Customer Advances	-	-	-	-	-	-		-	-	-	R	-
Prepayments - Pension	43,984,201	30,594,236	2,382,562	2,311,254	3,875,793	2,742,090		8,929,138	1,583,790	494,474	R	9,749,785
Deferred Taxes (190.1)	-	-	-	-	-	-		-	-	-	R	-
Deferred Taxes (281.1)	-	-	-	-	-	-		-	-	-	R	-
Deferred Taxes (282.1)	-	-	-	-	-	-		-	-	-	R	-
Deferred Taxes (283.1)	-	-	-	-	-	-		-	-	-	R	-
Deferred Taxes - State (283.1)	-	-	-	-	-	-		-	-	-	R	-
Deferred Investment Tax Credits (255)	-	-	-	-	-	-		-	-	-	R	-
Total	(11,127,945)	(5,143,104)	294,604	(10,468,509)	567,916	1,594,062		(8,306,531)	1,532,612	494,474	R	(2,466,683)
											R	-
Total Rate Base	73,320,774	52,234,807	4,785,595	(6,124,368)	7,869,317	6,771,607		8,516,556	5,880,543	1,903,274	R	16,252,695
											7.28%	$ 1,183,196
Operating Expense												
O&M Expense												
Distribution Operation												
580 Supervision & Engineering	-	-	-	-	-	-		-	-	-	R	-
581 Load Dispatching	-	-	-	-	-	-		-	-	-	R	-
582 Station Equipment	-	-	-	-	-	-		-	-	-	R	-
583 Overhead Lines	-	-	-	-	-	-		-	-	-	R	-
584 Undergroung Lines	-	-	-	-	-	-		-	-	-	R	-
585 Street Lighting	-	-	-	-	-	-		-	-	-	R	-
586 Meters	-	-	-	-	-	-		-	-	-	R	-
587 Customer Installations	-	-	-	-	-	-		-	-	-	R	-
588 Miscellaneous Distribution	-	-	-	-	-	-		-	-	-	R	-
589 Rents	-	-	-	-	-	-		-	-	-	R	-
Total	-	-	-	-	-	-		-	-	-	R	-
Distribution Maintenance											R	-
590 Supervision & Engineering	-	-	-	-	-	-		-	-	-	R	-
591 Structures	-	-	-	-	-	-		-	-	-	R	-
592 Station Equipment	-	-	-	-	-	-		-	-	-	R	-
593 Overhead Lines	-	-	-	-	-	-		-	-	-	R	-
594 Underground Lines	-	-	-	-	-	-		-	-	-	R	-
595 Line Transformers	-	-	-	-	-	-		-	-	-	R	-
596 Street Lighting	-	-	-	-	-	-		-	-	-	R	-
597 Meters	-	-	-	-	-	-		-	-	-	R	-
598 Miscellaneous Distribution	-	-	-	-	-	-		-	-	-	R	-
Total	-	-	-	-	-	-		-	-	-	R	-
Customer Accounts												
901 Supervision & Engineering	282,405	249,769	16,396	9,263	213	40		9,516	6,584	141	C	107,830
902 Meter Reading	-	-	-	-	-	-		-	-	-	R	-
903 Customer Records & Collection Exp.	39,409,324	35,018,387	2,173,600	1,140,662	23,015	3,580		1,167,258	1,028,944	21,136	C	15,047,530
904 Uncollectible Accounts	106,585	61,316	2,987	28,643	10,129	807		39,579	1,683	1,020	R	23,626
Factoring Expense	29,770,922	17,797,465	1,058,691	7,352,908	2,614,794	121,594		10,089,296	517,945	307,525	R	6,599,190
431-Interest on Customer Deposits	1,759,231	1,140,769	66,650	407,942	105,590	36,646		550,178	1,634	-	R	389,961
905 Miscellaneous Customer Accounts	372,095	329,093	21,603	12,204	281	53		12,539	8,675	185	C	142,076
Total	71,700,562	54,596,799	3,339,926	8,951,621	2,754,023	162,722		11,868,366	1,565,463	330,008		22,310,213

Ohio Power Company Rate Increase Request
PUCO Case No. 20-585-EL-AIR
Allocation of Costs to SSO

Label	Total Retail	RS: Residential	GS: Non-Demand Metered	GS: Demand Metered - SEC	GS: Demand Metered - PRI	GS: Demand Metered - SUB/TRAN	Total GS - DM	OL: Outdoor Lighting	SL: Street Lighting	Allocator	Allocation to SSO
	1	2	3	4	5	6	7	8	9		
Customer Service & Inf & Sales Exp											
907 Supervision	3,843,586	2,948,239	187,548	465,389	138,879	8,275	612,543	78,672	16,585	C	1,467,584
908 Customer Assistance	7,857,033	6,026,770	383,384	951,345	283,895	16,915	1,252,156	160,821	33,902	C	3,000,025
Cust Assist. Exp. - DSM – 907, 908, 911	-	-	-	-	-	-	-	-	-	A	-
908.0009 Cust Assist. Exp.	84,988	65,190	4,147	10,290	3,071	183	13,544	1,740	367	C	32,451
909 Information & Instruction	(77)	(59)	(4)	(9)	(3)	(0)	(12)	(2)	(0)	C	(29)
910 Miscellaneous Customer Service	24,475	18,774	1,194	2,963	884	53	3,901	501	106	C	9,345
911-916 Misc Selling Expense	651,573	499,792	31,794	78,894	23,543	1,403	103,840	13,337	2,811	A	651,573
Total	12,461,579	9,558,706	608,063	1,508,873	450,270	26,829	1,985,971	255,069	53,770		5,160,948
Administrative & General Expense											
920-Salaries	35,977,394	21,747,766	1,191,357	8,443,052	3,455,330	597,315	12,495,697	391,482	151,093	C	13,737,128
921-Office Supplies	3,463,342	2,093,536	114,685	812,765	332,625	57,500	1,202,891	37,686	14,545	C	1,322,396
922-Admin Exp Transferred	(7,953,963)	(4,808,045)	(263,388)	(1,866,609)	(763,912)	(132,056)	(2,762,577)	(86,550)	(33,404)	C	(3,037,035)
923.0001 Outside Svcs Empl - Non-Assoc.	5,803,269	3,507,985	192,170	1,361,891	557,356	96,349	2,015,596	63,147	24,372	R	1,286,385
923.0003 AEPSC Billed to Client Co.	2,549,835	1,541,335	84,435	598,386	244,890	42,334	885,611	27,746	10,708	R	565,211
924-Property Insurance	149,815	79,428	8,443	6,949	13,311	10,602	30,861	19,783	11,300	R	33,209
925-Injuries & Damages	1,500,445	1,043,670	81,277	78,844	132,216	93,542	304,602	54,028	16,868	R	332,597
926.0000 OPEB - Employee Benefits	1,044,778	726,719	56,594	54,900	92,064	65,134	212,098	37,621	11,745	C	398,924
926.0003 Pension Plan	1,129,323	785,527	61,174	59,343	99,513	70,405	229,261	40,665	12,696	C	431,205
927-Franchise Requirements	-	-	-	-	-	-	-	-	-		-
9280000 Reg. Commission Exp.	1,129,780	675,398	40,176	279,036	99,229	4,614	382,880	19,656	11,670	R	250,433
929 Duplicate Charges	-	-	-	-	-	-	-	-	-		-
930.1 Gen. Advertising Exp.	1,343,776	812,291	44,498	315,353	129,059	22,310	466,721	14,622	5,643	A	1,343,776
930.2000 Misc. General Expenses	4,618,234	2,791,649	152,928	1,083,791	443,543	76,674	1,604,009	50,252	19,395	C	1,763,365
930.2007 ABD Exp.	1,550,917	892,211	43,464	416,780	147,385	11,744	575,908	24,487	14,848	C	592,182
931 Rent	2,267,361	1,370,584	75,081	532,097	217,761	37,644	787,502	24,672	9,522	C	865,739
935 A&G - Maintenance	2,562,836	1,782,641	138,825	134,670	225,832	159,774	520,276	92,283	28,812	C	978,559
Total	57,137,143	35,042,694	2,021,720	12,311,249	5,426,202	1,213,885	18,951,337	811,579	309,813		20,864,075
Total O&M Expense	141,299,283	99,198,198	5,969,710	22,771,743	8,630,495	1,403,436	32,805,673	2,632,111	693,591		48,335,235
Depreciation & Amortization Expense											
Distribution	-	-	-	-	-	-	-	-	-	R	-
General & Intangible	10,543,698	7,333,915	571,137	554,044	929,088	657,322	2,140,453	379,659	118,533	R	2,337,175
Total Depreciation & Amort Expense	10,543,698	7,333,915	571,137	554,044	929,088	657,322	2,140,453	379,659	118,533		2,337,175
Taxes Other Than Income											
Payroll Taxes	1,798,411	1,250,927	97,417	94,502	158,472	112,118	365,092	64,757	20,218	C	686,681
Commercial Activity Taxes	7,236,405	4,326,022	257,336	1,787,268	635,577	29,556	2,452,401	125,897	74,750	R	1,604,062
Property Taxes	24,875,620	14,124,692	1,389,507	1,188,689	2,206,039	1,712,653	5,107,382	2,741,116	1,512,922	C	9,498,175
Regulatory Fees	3,305,646	1,976,160	117,553	816,438	290,336	13,501	1,120,276	57,511	34,146	R	732,748
Franchise Tax	2,227	1,331	79	550	196	9	755	39	23	R	494
Miscellaneous Taxes	-	-	-	-	-	-	-	-	-		-
Total Taxes Other Than Income	37,218,309	21,679,133	1,861,892	3,887,447	3,290,620	1,867,837	9,045,904	2,989,320	1,642,060		12,522,160
Other Expense											
Accretion	-	-	-	-	-	-	-	-	-		-
Total Operating Expense Before Income Tax	189,061,290	128,211,246	8,402,740	27,213,234	12,850,203	3,928,594	43,992,031	6,001,090	2,454,184		$ 63,194,571
Total Allocation to SSO											**$ 64,377,767**

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing *Direct Testimony of Frank Lacey on Behalf Of Interstate Gas Supply, Inc. and Direct Energy Business, LLC & Direct Energy Services, LLC* was filed electronically through the Docketing Information System of the Public Utilities Commission of Ohio on April 20, 2021. The Commission's e-filing system will electronically serve notice of the filing of this document upon the following parties listed below.

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