OFFICIAL COPY

INFORMATION SHEET

PRESIDING: Chair Mitchell, Commissioners Brown-Bland, Gray, Clodfelter
PLACE: Dobbs Building, Raleigh, North Carolina
DATE: July 15, 2019
TIME: 1:30: p.m. to 5:30 p.m.
DOCKET NO.: E-100, Sub 158
COMPANIES: Duke Energy Progress, LLC, Duke Energy Carolinas, LLC, and Dominion Energy North Carolina
DESCRIPTION: In the Matter of Generic Electric, Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2018
VOLUME: 2

APPEARANCES
(See attached.)

EXHIBITS

(See attached.)

COPIES ORDERED: Email: Fentress, Grigg, Dantonio, Smith, Bowen, Hutt, Kemerait, Levitas, Ross, Snowden, Wills, Quinn, Harrod, Dodge, Cummings
REPORTED BY: Linda Garrett TRANSCRIPT PAGES: 185
TRANSCRIBED BY: Linda Garrett PREFILED PAGES: 231
DATE TRANSCRIBED: July 23, 2019

A P P E A R A N C E S:

FOR DUKE ENERGY CAROLINAS, LLC
AND DUKE ENERGY PROGRESS, LLC:
Kendrick Fentress, Esq.
Duke Energy Corporation
Associate General Counsel
410 S. Wilmington Street
Raleigh, North Carolina 27602

E. Brett Breitschwerdt, Esq.
McGuireWoods LLP
434 Fayetteville Street, Suite 2600
Raleigh, North Carolina 27601

FOR DOMINION ENERGY NORTH CAROLINA:
Mary Lynne Grigg, Esq.
Nick Dantonio, Esq.
McGuireWoods LLP
434 Fayetteville Street, Suite 2600
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:

Benjamin Smith, Esq.
Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY:

Lauren Bowen, Esq.
Senior Attorney
Maia Hutt, Esq.
Associate Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

FOR NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE and ECOPLEXUS, INC.:

Karen M. Kemerait, Esq.
Fox Rothschild, LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

A P P E A R A N C E S (Cont'd.)

FOR NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE:

Steven Levitas, Esq.
Kilpatrick Townsend
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

FOR NORTH CAROLINA SMALL HYDRO GROUP:

Deborah Ross, Esq.
Fox Rothschild, LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR CUBE YADKIN GENERATION:

Ben Snowden, Esq.
Kilpatrick Townsend & Stockton
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

A P P E A R A N C E S Cont'd.:

FOR NC WARN:

Kristen Wills, Esq.
2812 Hillsborough Road
Durham, North Carolina 27705

Matthew D. Quinn, Esq.
Lewis & Roberts, PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION, INC.:

Robert F. Page, Esq.
Crisp & Page
4010 Barrett Drive, Suite 205
Raleigh, North Carolina 27609

A P P E A R A N C E S (Cont'd.):

FOR THE USING AND CONSUMING PUBLIC AND ON BEHALF OF THE STATE AND ITS CITIZENS IN THIS MATTER AFFECTING THE PUBLIC INTEREST:

Jennifer Harrod, Esq.
Special Deputy Attorney General
Teresa Townsend, Esq.
Special Deputy Attorney General
Office of the North Carolina Attorney General
114 West Edenton Street
Raleigh, North Carolina 27603

FOR THE USING AND CONSUMING PUBLIC:

Tim Dodge, Esq.
Layla Cummings, Esq.
Lucy Edmondson, Esq.
Heather Fennell, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

T A B L E O F C O N T E N T S

E X A M I N A T I O N S

E X H I B I T S

I/A
Vol. 2

Wilson Exhibit A

James F. Wilson
Principal, Wilson Energy Economics

4800 Hampden Lane Suite 200
Bethesda, Maryland 20814 USA

Phone: (240) 482-3737
Cell: (301) 535-6571
Email: jwilson@wilsonenec.com
www.wilsonenec.com

SUMMARY

James F. Wilson is an economist with over 30 years of consulting experience, primarily in the electric power and natural gas industries. Many of his assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in California, PJM, New England, Russia and other regions. He also spent five years in Russia in the early 1990s advising on the reform, restructuring and development of the Russian electricity and natural gas industries.

Mr. Wilson has submitted affidavits and testified in Federal Energy Regulatory Commission and state regulatory proceedings. His papers have appeared in the *Energy Journal*, *Electricity Journal*, *Public Utilities Fortnightly* and other publications, and he often presents at industry conferences.

Prior to founding Wilson Energy Economics, Mr. Wilson was a Principal at LECG, LLC. He has also worked for ICF Resources, Decision Focus Inc., and as an independent consultant.

EDUCATION

MS, Engineering-Economic Systems, Stanford University, 1982

BA, Mathematics, Oberlin College, 1977

RECENT ENGAGEMENTS

- Evaluated the potential impact of an electricity generation operating reserve demand curve on a wholesale electricity market with a capacity construct.
- Developed wholesale capacity market enhancements to accommodate seasonal resources and resource adequacy requirements.
- Evaluation of wholesale electricity market design enhancements to accommodate state initiatives to promote state environmental and other policy objectives.
- Evaluation of proposals for natural gas distribution system expansions.
- Various consulting assignments on wholesale electric capacity market design issues in PJM, New England, the Midwest, Texas, and California.
- Cost-benefit analysis of a new natural gas pipeline.
- Evaluation of the impacts of demand response on electric generation capacity mix and emissions.
- Panelist on a FERC technical conference on capacity markets.
- Affidavit on the potential for market power over natural gas storage.
- Executive briefing on wind integration and linkages to short-term and longer-term resource adequacy approaches.

- Affidavit on the impact of a centralized capacity market on the potential benefits of participation in a Regional Transmission Organization (RTO).
- Participated in a panel teleseminar on resource adequacy policy and modeling.
- Affidavit on opt-out rules for centralized capacity markets.
- Affidavits on minimum offer price rules for RTO centralized capacity markets.
- Evaluated electric utility avoided cost in a tax dispute.
- Advised on pricing approaches for RTO backstop short-term capacity procurement.
- Affidavit evaluating the potential impact on reliability of demand response products limited in the number or duration of calls.
- Evaluated changing patterns of natural gas production and pipeline flows, developed approaches for pipeline tolls and cost recovery.
- Evaluated an electricity peak load forecasting methodology and forecast; evaluated regional transmission needs for resource adequacy.
- Participated on a panel teleseminar on natural gas price forecasting.
- Affidavit evaluating a shortage pricing mechanism and recommending changes.
- Testimony in support of proposed changes to a forward capacity market mechanism.
- Reviewed and critiqued an analysis of the economic impacts of restrictions on oil and gas development.
- Advised on the development of metrics for evaluating the performance of Regional Transmission Organizations and their markets.
- Prepared affidavit on the efficiency benefits of excess capacity sales in readjustment auctions for installed capacity.
- Prepared affidavit on the potential impacts of long lead time and multiple uncertainties on clearing prices in an auction for standard offer electric generation service.

EARLIER PROFESSIONAL EXPERIENCE

LECG, LCC, Washington, DC 1998–2009.
<u>Principal</u>

- Reviewed and commented on an analysis of the target installed capacity reserve margin for the Mid Atlantic region; recommended improvements to the analysis and assumptions.
- Evaluated an electric generating capacity mechanism and the price levels to support adequate capacity; recommended changes to improve efficiency.
- Analyzed and critiqued the methodology and assumptions used in preparation of a long run electricity peak load forecast.
- Evaluated results of an electric generating capacity incentive mechanism and critiqued the mechanism's design; prepared a detailed report. Evaluated the impacts of the mechanism's flaws on prices and costs and prepared testimony in support of a formal complaint.
- Analyzed impacts and potential damages of natural gas migration from a storage field.
- Evaluated allegations of manipulation of natural gas prices and assessed the potential impacts of natural gas trading strategies.
- Prepared affidavit evaluating a pipeline's application for market-based rates for interruptible transportation and the potential for market power.
- Prepared testimony on natural gas industry contracting practices and damages in a contract dispute.
- Prepared affidavits on design issues for an electric generating capacity mechanism for an eastern US regional transmission organization; participated in extensive settlement discussions.
- Prepared testimony on the appropriateness of zonal rates for a natural gas pipeline.
- Evaluated market power issues raised by a possible gas-electric merger.
- Prepared testimony on whether rates for a pipeline extension should be rolled-in or incremental under Federal Energy Regulatory Commission ("FERC") policy.

- Prepared an expert report on damages in a natural gas contract dispute.
- Prepared testimony regarding the incentive impacts of a ratemaking method for natural gas pipelines.
- Prepared testimony evaluating natural gas procurement incentive mechanisms.
- Analyzed the need for and value of additional natural gas storage in the southwestern US.
- Evaluated market issues in the restructured Russian electric power market, including the need to introduce financial transmission rights, and policies for evaluating mergers.
- Affidavit on market conditions in western US natural gas markets and the potential for a new merchant gas storage facility to exercise market power.
- Testimony on the advantages of a system of firm, tradable natural gas transmission and storage rights, and the performance of a market structure based on such policies.
- Testimony on the potential benefits of new independent natural gas storage and policies for providing transmission access to storage users.
- Testimony on the causes of California natural gas price increases during 2000-2001 and the possible exercise of market power to raise natural gas prices at the California border.
- Advised a major US utility with regard to the Federal Energy Regulatory Commission's proposed Standard Market Design and its potential impacts on the company.
- Reviewed and critiqued draft legislation and detailed market rules for reforming the Russian electricity industry, for a major investor in the sector.
- Analyzed the causes of high prices in California wholesale electric markets during 2000 and developed recommendations, including alternatives for price mitigation. Testimony on price mitigation measures.
- Summarized and critiqued wholesale and retail restructuring and competition policies for electric power and natural gas in select US states, for a Pacific Rim government contemplating energy reforms.
- Presented testimony regarding divestiture of hydroelectric generation assets, potential market power issues, and mitigation approaches to the California Public Utilities Commission.
- Reviewed the reasonableness of an electric utility's wholesale power purchases and sales in a restructured power market during a period of high prices.
- Presented an expert report on failure to perform and liquidated damages in a natural gas contract dispute.
- Presented a workshop on Market Monitoring to a group of electric utilities in the process of forming an RTO.
- Authored a report on the screening approaches used by market monitors for assessing exercise of market power, material impacts of conduct, and workable competition.
- Developed recommendations for mitigating locational market power, as part of a package of congestion management reforms.
- Provided analysis in support of a transmission owner involved in a contract dispute with generators providing services related to local grid reliability.
- Authored a report on the role of regional transmission organizations in market monitoring.
- Prepared market power analyses in support of electric generators' applications to FERC for market-based rates for energy and ancillary services.
- Analyzed western electricity markets and the potential market power of a large producer under various asset acquisition or divestiture strategies.
- Testified before a state commission regarding the potential benefits of retail electric competition and issues that must be addressed to implement it.
- Prepared a market power analysis in support of an acquisition of generating capacity in the New England market.
- Advised a California utility regarding reform strategies for the California natural gas industry, addressing market power issues and policy options for providing system balancing services.

ICF RESOURCES, INC., Fairfax, VA, 1997–1998.
Project Manager

- Reviewed, critiqued and submitted testimony on a New Jersey electric utility's restructuring proposal, as part of a management audit for the state regulatory commission.
- Assisted a group of US utilities in developing a proposal to form a regional Independent System Operator (ISO).
- Researched and reported on the emergence of Independent System Operators and their role in reliability, for the Department of Energy.
- Provided analytical support to the Secretary of Energy's Task Force on Electric System Reliability on various topics, including ISOs. Wrote white papers on the potential role of markets in ensuring reliability.
- Recommended near-term strategies for addressing the potential stranded costs of non-utility generator contracts for an eastern utility; analyzed and evaluated the potential benefits of various contract modifications, including buyout and buydown options; designed a reverse auction approach to stimulating competition in the renegotiation process.
- Designed an auction process for divestiture of a Northeastern electric utility's generation assets and entitlements (power purchase agreements).
- Participated in several projects involving analysis of regional power markets and valuation of existing or proposed generation assets.

IRIS MARKET ENVIRONMENT PROJECT, 1994–1996.
Project Director, Moscow, Russia

Established and led a policy analysis group advising the Russian Federal Energy Commission and Ministry of Economy on economic policies for the electric power, natural gas, oil pipeline, telecommunications, and rail transport industries (*the Program on Natural Monopolies,* a project of the IRIS Center of the University of Maryland Department of Economics, funded by USAID):

- Advised on industry reforms and the establishment of federal regulatory institutions.
- Advised the Russian Federal Energy Commission on electricity restructuring, development of a competitive wholesale market for electric power, tariff improvements, and other issues of electric power and natural gas industry reform.
- Developed policy conditions for the IMF's $10 billion Extended Funding Facility.
- Performed industry diagnostic analyses with detailed policy recommendations for electric power (1994), natural gas, rail transport and telecommunications (1995), oil transport (1996).

Independent Consultant stationed in Moscow, Russia, 1991–1996

Projects for the WORLD BANK, 1992-1996:

- Bank Strategy for the Russian Electricity Sector. Developed a policy paper outlining current industry problems and necessary policies, and recommending World Bank strategy.
- Russian Electric Power Industry Restructuring. Participated in work to develop recommendations to the Russian Government on electric power industry restructuring.
- Russian Electric Power Sector Update. Led project to review developments in sector restructuring, regulation, demand, supply, tariffs, and investment.
- Russian Coal Industry Restructuring. Analyzed Russian and export coal markets and developed forecasts of future demand for Russian coal.
- World Bank/IEA Electricity Options Study for the G-7. Analyzed mid- and long-term electric power demand and efficiency prospects and developed forecasts.
- Russian Energy Pricing and Taxation. Developed recommendations for liberalizing energy markets, eliminating subsidies and restructuring tariffs for all energy resources.

Other consulting assignments in Russia, 1991–1994:

- Advised on projects pertaining to Russian energy policy and the transition to a market economy in the energy industries, for the Institute for Energy Research of the Russian Academy of Sciences.
- Presented seminars on the structure, economics, planning, and regulation of the energy and electric power industries in the US, for various Russian clients.

DECISION FOCUS INC., Mountain View, CA, 1983–1992
Senior Associate, 1985-1992.

- For the Electric Power Research Institute, led projects to develop decision-analytic methodologies and models for evaluating long term fuel and electric power contracting and procurement strategies. Applied the methodologies and models in numerous case studies, and presented several workshops and training sessions on the approaches.
- Analyzed long-term and short-term natural gas supply decisions for a large California gas distribution company following gas industry unbundling and restructuring.
- Analyzed long term coal and rail alternatives for a midwest electric utility.
- Evaluated bulk power purchase alternatives and strategies for a New Jersey electric utility.
- Performed a financial and economic analysis of a proposed hydroelectric project.
- For a natural gas pipeline company serving the Northeastern US, forecasted long-term natural gas supply and transportation volumes. Developed a forecasting system for staff use.
- Analyzed potential benefits of diversification of suppliers for a natural gas pipeline company.
- Evaluated uranium contracting strategies for an electric utility.
- Analyzed telecommunications services markets under deregulation, developed and implemented a pricing strategy model. Evaluated potential responses of residential and business customers to changes in the client's and competitors' telecommunications services and prices.
- Analyzed coal contract terms and supplier diversification strategies for an eastern electric utility.
- Analyzed oil and natural gas contracting strategies for an electric utility.

TESTIMONY AND AFFIDAVITS

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2019 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-20221, Direct Testimony on behalf of Michigan Environmental Council, May 28, 2019.

PJM Interconnection, L.L.C., FERC Docket Nos. EL19-58 and ER19-1486 (Reserve Pricing - ORDC), Affidavit in Support of the Protest of the Clean Energy Advocates, May 15, 2019.

PJM Interconnection, L.L.C., FERC Docket Nos. EL19-58 and ER19-1486 (Reserve Pricing - Transition), Affidavit in Support of the Protests of the PJM Load/Customer Coalition and Clean Energy Advocates, May 15, 2019.

In Re: Georgia Power Company's 2019 Integrated Resource Plan, Georgia Public Service Commission Docket No. 42310, Direct Testimony on Behalf of Georgia Interfaith Power & Light and the Partnership For Southern Equity, April 25, 2019; testimony at hearings May 14, 2019.

PJM Interconnection, L.L.C., FERC Docket No. EL19-63 (RPM Market Supplier Offer Cap), Affidavit in Support of the Complaint of the Joint Consumer Advocates, April 15, 2019.

In the Matter of 2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans, North Carolina Utilities Commission Docket No. E-100 Sub 157, Review and Evaluation of the Load Forecasts, and Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues, with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans, Attachments 3 and 4 to the comments of Southern Alliance for Clean Energy, Sierra Club, and the Natural Resources Defense Council, March 7, 2019.

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018, North Carolina Utilities Commission Docket No. E-100 Sub 158, Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing, Attachment B to the Initial Comments of the Southern Alliance for Clean Energy, February 12, 2019.

PJM Interconnection, L.L.C., FERC Docket No. ER19-105 (RPM Quadrennial Review), Affidavit in Support of the Limited Protest and Comments of the Public Interest Entities, November 19, 2018.

PJM Interconnection, L.L.C., FERC Docket No. EL18-178 (MOPR and FRR Alternative), Affidavit in Support of the Comments of the FRR-RS Supporters, October 2, 2018; Reply Affidavit on behalf of Clean Energy and Consumer Advocates, November 6, 2018.

Virginia Electric and Power Company's 2018 Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUE-2018-00065, Direct Testimony on behalf of Environmental Respondents, August 10, 2018; testimony at hearings September 25, 2018; Supplemental Testimony, April 16, 2019.

In the Matter of the Application of Duke Energy Ohio for an Increase in Electric Distribution Rates, etc., Public Utilities Commission of Ohio Case No. 17-32-EL-AIR et al, Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, June 25, 2018; deposition, July 3, 2018; testimony at hearings, July 19, 2018.

In the Matter of the Application of DTE Gas Company for Approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 Months ending March 31, 2019, Michigan Public Service Commission Case No. U-18412, Direct Testimony on behalf of Michigan Environmental Council, June 7, 2018.

Constellation Mystic Power, L.L.C., FERC Docket No. ER18-1639-000 (Mystic Cost of Service Agreement), Affidavit in Support of the Comments of New England States Committee on Electricity, June 6, 2018; prepared answering testimony, August 23, 1018.

New England Power Generators Association, Complainant v. ISO New England Inc. Respondent, FERC Docket No. EL18-154-000 (re: capacity offer price of Mystic power plant), Affidavit in Support of the Protest of New England States Committee on Electricity, June 6, 2018.

PJM Interconnection, L.L.C., FERC Docket No. ER18-1314 (Capacity repricing or MOPR-Ex), Affidavit in Support of the Protests of DC-MD-NJ Consumer Coalition, Joint Consumer Advocates, and Clean Energy Advocates, May 7, 2018; reply affidavit, June 15, 2018.

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2018 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-18403, Direct Testimony on behalf of Michigan Environmental Council and Sierra Club, April 20, 2018.

Virginia Electric and Power Company's 2017 Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUE-2017-00051, Direct Testimony on behalf of Environmental Respondents, August 11, 2017; testimony at hearings September 26, 2017.

Ohio House of Representatives Public Utilities Committee hearing on House Bill 178 (Zero Emission Nuclear Resource legislation), Opponent Testimony on Behalf of Natural Resources Defense Council, May 15, 2017.

In the Matter of the Application of Atlantic Coast Pipeline, Federal Energy Regulatory Commission Docket No. CP15-554, Evaluating Market Need for the Atlantic Coast Pipeline, Attachment 2 to the comments of Shenandoah Valley Network *et al*, April 6, 2017.

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2017 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-18143, Direct Testimony on behalf of Michigan Environmental Council and Sierra Club, March 22, 2017.

In the Matter of the Petition of Washington Gas Light Company for Approval of Revised Tariff Provisions to Facilitate Access to Natural Gas in the Company's Maryland Franchise Area That Are Currently Without Natural Gas Service, Maryland Public Service Commission Case No. 9433, Direct

Testimony on Behalf of the Mid-Atlantic Propane Gas Association and the Mid-Atlantic Petroleum Distributors Association, Inc., March 1, 2017; testimony at hearings, May 1, 2017.

In the Matter of Integrated Resource Plans and Related 2016 REPS Compliance Plans, North Carolina Utilities Commission Docket No. E-100 Sub 147, Review and Evaluation of the Peak Load Forecasts and Reserve Margin Determinations for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans, Attachments A and B to the comments of the Natural Resources Defense Council, Southern Alliance for Clean Energy, and the Sierra Club, February 17, 2017.

In the Matter of the Tariff Revisions Designated TA285-4 filed by ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc., Regulatory Commission of Alaska Case No. U-16-066, Testimony on Behalf of Matanuska Electric Association, Inc., February 7, 2017, testimony at hearings, June 21, 2017.

PJM Interconnection, L.L.C., FERC Docket No. ER17-367 (seasonal capacity), Prepared Testimony on Behalf of Advanced Energy Management Alliance, Environmental Law & Policy Center, Natural Resources Defense Council, Rockland Electric Company and Sierra Club, December 8, 2016; Declaration in support of Protest of Response to Deficiency Letter, February 13, 2017.

Natural Resources Defense Council, Sierra Club, and Union of Concerned Scientists v. Federal Energy Regulatory Commission, U.S. District Court of Appeals for the D.C. Circuit Case No. 16-1236 (Capacity Performance), Declaration, September 23, 2016.

Mountaineer Gas Company Infrastructure Replacement and Expansion Program Filing for 2016, West Virginia Public Service Commission Case No. 15-1256-G-390P, and Mountaineer Gas Company Infrastructure Replacement and Expansion Program Filing for 2017, West Virginia Public Service Commission Case No. 16-0922-G-390P, Direct Testimony on behalf of the West Virginia Propane Gas Association, September 9, 2016.

Application of Chesapeake Utilities Corporation for a General Increase in its Natural Gas Rates and for Approval of Certain Other Changes to its Natural Gas Tariff, Delaware P.S.C. Docket No. 15-1734, Direct Testimony on behalf of the Delaware Association Of Alternative Energy Providers, Inc., August 24, 2016.

Virginia Electric and Power Company's 2016 Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUE-2016-00049, Direct Testimony on behalf of Environmental Respondents, August 17, 2016; testimony at hearings October 5, 2016.

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2016 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-17920, Direct Testimony on behalf of Michigan Environmental Council and Sierra Club, March 14, 2016.

In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider, Public Utilities Commission of Ohio Case No. 14-1693-EL-RDR: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, September 11, 2015; deposition, September 30, 2015; supplemental deposition, October 16, 2015; testimony at hearings, October 21, 2015; supplemental testimony December 28, 2015; second supplemental deposition, December 30, 2015; testimony at hearings January 8, 2016.

Indicated Market Participants v. PJM Interconnection, L.L.C., FERC Docket No. EL15-88 (Capacity Performance transition auctions), Affidavit on behalf of the Joint Consumer Representatives and Interested State Commissions, August 17, 2015.

ISO New England Inc. and New England Power Pool Participants Committee, FERC Docket No. ER15-2208 (Winter Reliability Program), Testimony on Behalf of the New England States Committee on Electricity, August 5, 2015.

Joint Consumer Representatives v. PJM Interconnection, L.L.C., FERC Docket No. EL15-83 (load forecast for capacity auctions), Affidavit in Support of the Motion to Intervene and Comments of the Public Power Association of New Jersey, July 20, 2015.

In the Matter of the Tariff Revisions Filed by ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc., Regulatory Commission of Alaska Case No. U-14-111, Testimony on Behalf of Matanuska Electric Association, Inc., May 13, 2015.

In the Matter of the Application of Ohio Edison Company et al for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 14-1297-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel and Northeast Ohio Public Energy Council, December 22, 2014; deposition, February 10, 2015; supplemental testimony May 11, 2015; second deposition May 26, 2015; testimony at hearings, October 2, 2015; second supplemental testimony December 30, 2015; third deposition January 8, 2016; testimony at hearings January 19, 2016; rehearing direct testimony June 22, 2016; fourth deposition July 5, 2016; testimony at hearings July 14, 2016.

PJM Interconnection, L.L.C., FERC Docket No. ER14-2940 (RPM Triennial Review), Affidavit in Support of the Protest of the PJM Load Group, October 16, 2014.

In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 14-841-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, September 26, 2014; deposition, October 6, 2014; testimony at hearings, November 5, 2014.

In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 13-2385-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, May 6, 2014; deposition, May 29, 2014; testimony at hearings, June 16, 2014.

PJM Interconnection, L.L.C., FERC Docket No. ER14-504 (clearing of Demand Response in RPM), Affidavit in Support of the Protest of the Joint Consumer Advocates and Public Interest Organizations, December 20, 2013.

New England Power Generators Association, Inc. v. ISO New England Inc., FERC Docket No. EL14-7 (administrative capacity pricing), Testimony in Support of the Protest of the New England States Committee on Electricity, November 27, 2013.

Midwest Independent Transmission System Operator, Inc., FERC Docket No. ER11-4081 (minimum offer price rule), Affidavit In Support of Brief of the Midwest TDUs, October 11, 2013.

ANR Storage Company, FERC Docket No. RP12-479 (storage market-based rates), Prepared Answering Testimony on behalf of the Joint Intervenor Group, April 2, 2013; Prepared Cross-answering Testimony, May 15, 2013; testimony at hearings, September 4, 2013.

In the Matter of the Application of The Dayton Power and Light Company for Approval of its Market Rate Offer, Public Utilities Commission of Ohio Case No. 12-426-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, March 5, 2013; deposition, March 11, 2013.

PJM Interconnection, L.L.C., FERC Docket No. ER13-535 (minimum offer price rule), Affidavit in Support of the Protest and Comments of the Joint Consumer Advocates, December 28, 2012.

In the Matter of the Application of Ohio Edison Company, et al for Authority to Provide for a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 12-1230-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, May 21, 2012; deposition, May 30, 2012; testimony at hearings, June 5, 2012.

PJM Interconnection, L.L.C., FERC Docket No. ER12-513 (changes to RPM), Affidavit in Support of Protest of the Joint Consumer Advocates and Demand Response Supporters, December 22, 2011.

People of the State of Illinois *ex rel.* Leon A. Greenblatt, III v Commonwealth Edison Company, Circuit Court of Cook County, Illinois, deposition, September 22, 2011; interrogatory, Feb. 22, 2011.

In the Matter of the Application of Union Electric Company for Authority to Continue the Transfer of Functional Control of Its Transmission System to the Midwest Independent Transmission System Operator, Inc., Missouri PSC Case No. EO-2011-0128, Testimony in hearings, February 9, 2012; Rebuttal Testimony and Response to Commission Questions On Behalf Of The Missouri Joint Municipal Electric Utility Commission, September 14, 2011.

PJM Interconnection, L.L.C., and PJM Power Providers Group v. PJM Interconnection, L.L.C., FERC Docket Nos. ER11-2875 and EL11-20 (minimum offer price rule), Affidavit in Support of Protest of New Jersey Division of Rate Counsel, March 4, 2011, and Affidavit in Support of Request for Rehearing and for Expedited Consideration of New Jersey Division of Rate Counsel, May 12, 2011.

PJM Interconnection, L.L.C., FERC Docket No. ER11-2288 (demand response "saturation"), Affidavit in Support of Protest and Comments of the Joint Consumer Advocates, December 23, 2010.

North American Electric Reliability Corporation, FERC Docket No. RM10-10, Comments on Proposed Reliability Standard BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation, December 23, 2010.

In the Matter of the Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results, Maryland Public Service Commission Administrative Docket PC 22, Comments and Responses to Questions On Behalf of Southern Maryland Electric Cooperative, October 15, 2010.

PJM Interconnection, L.L.C., FERC Docket No. ER09-1063-004 (PJM compliance filing on pricing during operating reserve shortages): Affidavit In Support of Comments and Protest of the Pennsylvania Public Utility Commission, July 30, 2010.

ISO New England, Inc. and New England Power Pool, FERC Docket No. ER10-787 (minimum offer price rules): Direct Testimony On Behalf Of The Connecticut Department of Public Utility Control, March 30, 2010; Direct Testimony in Support of First Brief of the Joint Filing Supporters, July 1, 2010; Supplemental Testimony in Support of Second Brief of the Joint Filing Supporters, September 1, 2010.

PJM Interconnection, L.L.C., FERC Docket No. ER09-412-006 (RPM incremental auctions): Affidavit In Support of Protest of Indicated Consumer Interests, January 19, 2010.

In the Matter of the Application of Ohio Edison Company, et al for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Public Utilities Commission of Ohio Case No. 09-906-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, December 7, 2009; deposition, December 10, 2009, testimony at hearings, December 22, 2009.

Application of PATH Allegheny Virginia Transmission Corporation for Certificates of Public Convenience and Necessity to Construct Facilities: 765 kV Transmission Line through Loudon, Frederick and Clarke Counties, Virginia State Corporation Commission Case No. PUE-2009-00043: Direct Testimony on Behalf of Commission Staff, December 8, 2009.

PJM Interconnection, L.L.C., FERC Docket No. ER09-412-000: Affidavit on Proposed Changes to the Reliability Pricing Model on behalf of RPM Load Group, January 9, 2009; Reply Affidavit, January 26, 2009.

PJM Interconnection, L.L.C., FERC Docket No. ER09-412-000: Affidavit In Support of the Protest Regarding Load Forecast To Be Used in May 2009 RPM Auction, January 9, 2009.

Maryland Public Service Commission et al v. PJM Interconnection, L.L.C., FERC Docket No. EL08-67-000: Affidavit in Support Complaint of the RPM Buyers, May 30, 2008; Supplemental Affidavit, July 28, 2008.

PJM Interconnection, L.L.C., FERC Docket No. ER08-516: Affidavit On PJM's Proposed Change to RPM Parameters on Behalf of RPM Buyers, March 6, 2008.

PJM Interconnection, L.L.C., Reliability Pricing Model Compliance Filing, FERC Docket Nos. ER05-1410 and EL05-148: Affidavit Addressing RPM Compliance Filing Issues on Behalf of the Public Power Association of New Jersey, October 15, 2007.

TXU Energy Retail Company LP v. Leprino Foods Company, Inc., US District Court for the Northern District of California, Case No. C01-20289: Testimony at trial, November 15-29, 2006; Deposition, April 7, 2006; Expert Report on Behalf of Leprino Foods Company, March 10, 2006.

Gas Transmission Northwest Corporation, Federal Energy Regulation Commission Docket No. RP06-407: Reply Affidavit, October 26, 2006; Affidavit on Behalf of the Canadian Association of Petroleum Producers, October 18, 2006.

PJM Interconnection, L.L.C., Reliability Pricing Model, FERC Docket Nos. ER05-1410 and EL05-148: Supplemental Affidavit on Technical Conference Issues, June 22, 2006; Supplemental Affidavit Addressing Paper Hearing Topics, June 2, 2006; Affidavit on Behalf of the Public Power Association of New Jersey, October 19, 2005.

Maritimes & Northeast Pipeline, L.L.C., FERC Docket No. RP04-360-000: Prepared Cross Answering Testimony, March 11, 2005; Prepared Direct and Answering Testimony on Behalf of Firm Shipper Group, February 11, 2005.

Dynegy Marketing and Trade v. Multiut Corporation, US District Court of the Northern District of Illinois, Case. No. 02 C 7446: Deposition, September 1, 2005; Expert Report in response to Defendant's counterclaims, March 21, 2005; Expert Report on damages, October 15, 2004.

Application of Pacific Gas and Electric Company, California Public Utilities Commission proceeding A.04-03-021: Prepared Testimony, Policy for Throughput-Based Backbone Rates, on behalf of Pacific Gas and Electric Company, May 21, 2004.

Gas Market Activities, California Public Utilities Commission Order Instituting Investigation I.02-11-040: Testimony at hearings, July, 2004; Prepared Testimony, Comparison of Incentives Under Gas Procurement Incentive Mechanisms, on behalf of Pacific Gas and Electric Company, December 10, 2003.

Application of Red Lake Gas Storage, L.P., FERC Docket No. CP02-420, Affidavit in support of application for market-based rates for a proposed merchant gas storage facility, March 3, 2003.

Application of Pacific Gas and Electric Company, California Public Utilities Commission proceeding A.01-10-011: Testimony at hearings, April 1-2, 2003; Rebuttal Testimony, March 24, 2003; Prepared Testimony, Performance of the Gas Accord Market Structure, on behalf of Pacific Gas and Electric Company, January 13, 2003.

Application of Wild Goose Storage, Inc., California Public Utilities Commission proceeding A.01-06-029: Testimony at hearings, November, 2001; Prepared testimony regarding policies for backbone expansion and tolls, and potential ratepayer benefits of new storage, on behalf of Pacific Gas and Electric Company, October 24, 2001.

Public Utilities Commission of the State of California v. El Paso Natural Gas Co., FERC Docket No. RP00-241: Testimony at hearings, May-June, 2001; Prepared Testimony on behalf of Pacific Gas and Electric Company, May 8, 2001.

Application of Pacific Gas and Electric Company, California Public Utilities Commission proceeding A.99-09-053: Prepared testimony regarding market power consequences of divestiture of hydroelectric assets, December 5, 2000.

San Diego Gas & Electric Company, *et al*, FERC Docket No. EL00-95: Prepared testimony regarding proposed price mitigation measures on behalf of Pacific Gas and Electric Co., November 22, 2000.

Application of Harbor Cogeneration Company, FERC Docket No. ER99-1248: Affidavit in support of application for market-based rates for energy, capacity and ancillary services, December 1998.

Application of and Complaint of Residential Electric, Incorporated vs. Public Service Company of New Mexico, New Mexico Public Utility Commission Case Nos. 2867 and 2868: Testimony at hearings, November, 1998; Direct Testimony on behalf of Public Service Company of New Mexico on retail access issues, November, 1998.

Management audit of Public Service Electric and Gas' restructuring proposal for the New Jersey Board of Public Utilities: Prepared testimony on reliability and basic generation service, March 1998.

PUBLISHED ARTICLES

Forward Capacity Market CONEfusion, Electricity Journal Vol. 23 Issue 9, November 2010.

Reconsidering Resource Adequacy (Part 2): Capacity Planning for the Smart Grid, Public Utilities Fortnightly, May 2010.

Reconsidering Resource Adequacy (Part 1): Has the One-Day-in-Ten-Years Criterion Outlived Its Usefulness? Public Utilities Fortnightly, April 2010.

A Hard Look at Incentive Mechanisms for Natural Gas Procurement, with K. Costello, National Regulatory Research Institute Report No. 06-15, November 2006.

Natural Gas Procurement: A Hard Look at Incentive Mechanisms, with K. Costello, Public Utilities Fortnightly, February 2006, p. 42.

After the Gas Bubble: An Economic Evaluation of the Recent National Petroleum Council Study, with K. Costello and H. Huntington, Energy Journal Vol. 26 No. 2 (2005).

High Natural Gas Prices in California 2000-2001: Causes and Lessons, Journal of Industry, Competition and Trade, vol. 2:1/2, November 2002.

Restructuring the Electric Power Industry: Past Problems, Future Directions, Natural Resources and Environment, ABA Section of Environment, Energy and Resources, Volume 16 No. 4, Spring, 2002.

Scarcity, Market Power, Price Spikes, and Price Caps, Electricity Journal, November, 2000.

The New York ISO's Market Power Screens, Thresholds, and Mitigation: Why It Is Not A Model For Other Market Monitors, Electricity Journal, August/September 2000.

ISOs: A Grid-by-Grid Comparison, Public Utilities Fortnightly, January 1, 1998.

Economic Policy in the Natural Monopoly Industries in Russia: History and Prospects (with V. Capelik), Voprosi Ekonomiki, November 1995.

Meeting Russia's Electric Power Needs: Uncertainty, Risk and Economic Reform, Financial and Business News, April 1993.

Russian Energy Policy through the Eyes of an American Economist, Energeticheskoye Stroitelstvo, December 1992, p 2.

Fuel Contracting Under Uncertainty, with R. B. Fancher and H. A. Mueller, IEEE Transactions on Power Systems, February, 1986, p. 26-33.

OTHER ARTICLES, REPORTS AND PRESENTATIONS

Panel: Reserve Pricing, Organization of PJM States Spring Strategy Meeting, April 8, 2019.

Panel: Capacity Markets, AWEA Future Power Markets Summit 2018, September 5, 2018.

With Rob Gramlich, *Maintaining Resource Adequacy in PJM While Accommodating State Policies: A Proposal for the Resource-Specific FRR Alternative*, July 27, 2018, prepared for Sierra Club, Natural Resources Defense Council, District of Columbia Office of the People's Counsel, American Council on Renewable Energy.

Seasonal Capacity Technical Conference, Federal Energy Regulatory Commission Docket Nos. EL17-32 and EL17-36, *Pre-Conference Comments* April 11, 2018; panelist, April 24, 2018, post-conference comments July 13, 2018.

Panel: Demand Response, Organization of PJM States Spring Strategy Meeting, April 9, 2018.

Panel: Energy Price Formation, Organization of PJM States Spring Strategy Meeting, April 9, 2018.

Panel: Regional Reliability Standards: Requirements or Replaceable Relics? Harvard Electricity Policy Group Ninetieth Plenary Session, March 22, 2018.

Panel: Transitioning to 100% Capacity Performance: Implications to Wind, Solar, Hydro and DR; moderator; Infocast's Mid-Atlantic Power Market Summit, October 24, 2017.

Panel: PJM Market Design Proposals Addressing State Public Policy Initiatives; Organization of PJM States, Inc. Annual Meeting, Arlington, VA, October 3, 2017.

Post Technical Conference Comments, State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C., FERC Docket No. AD17-11, June 22, 2017.

Panel: How Can PJM Integrate Seasonal Resources into its Capacity Market? Organization of PJM States, Inc. Annual Meeting, Columbus Ohio, October 19, 2016.

IMAPP "Two-Tier" FCM Pricing Proposals: Description and Critique, prepared for the New England States Committee on Electricity, October 2016.

"Missing Money" Revisited: Evolution of PJM's RPM Capacity Construct, report prepared for American Public Power Association, September 2016.

Panel: PJM Grid 20/20: Focus on Public Policy Goals and Market Efficiency, August 18, 2016.

Panel: What is the PJM Load Forecast, Organization of PJM States, Inc. Annual Meeting, October 12, 2015.

PJM's "Capacity Performance" Tariff Changes: Estimated Impact on the Cost of Capacity, prepared for the American Public Power Association, October, 2015.

Panel: Capacity Performance (and Incentive) Reform, EUCI Conference on Capacity Markets: Gauging Their Real Impact on Resource Development & Reliability, August 15, 2015.

Panel on Load Forecasting, Organization of PJM States Spring Strategy Meeting, April 13, 2015.

Panelist for Session 2: Balancing Bulk Power System and Distribution System Reliability in the Eastern Interconnection, Meeting of the Eastern Interconnection States' Planning Council, December 11, 2014.

Panel: Impact of PJM Capacity Performance Proposal on Demand Response, Mid-Atlantic Distributed Resources Initiative (MADRI) Working Group Meeting #36, December 9, 2014.

Panel: Applying the Lessons Learned from Extreme Weather Events – What Changes Are Needed In PJM Markets and Obligations? Infocast PJM Market Summit, October 28, 2014.

Panel on RPM: What Changes Are Proposed This Year? Organization of PJM States, Inc. 10th Annual Meeting, Chicago Illinois, October 13-14, 2014.

Panel on centralized capacity market design going forward, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, Docket No. AD13-7, September 25, 2013; post-conference comments, January 8, 2014.

Economics of Planning for Resource Adequacy, NARUC Summer Meetings, Denver, Colorado, July 21, 2013.

The Increasing Need for Flexible Resources: Considerations for Forward Procurement, EUCI Conference on Fast and Flexi-Ramp Resources, Chicago, Illinois, April 23-24, 2013.

Panel on RPM Issues: Long Term Vision and Recommendations for Now, Organization of PJM States, Inc. Spring Strategy Meeting, April 3, 2013.

Comments On: The Economic Ramifications of Resource Adequacy Whitepaper, peer review of whitepaper prepared for EISPC and NARUC, March 24, 2013.

Resource Adequacy: Criteria, Constructs, Emerging Issues, Coal Finance 2013, Institute for Policy Integrity, NYU School of Law, March 19, 2013.

Panel Discussion – Alternative Models and Best Practices in Other Regions, Long-Term Resource Adequacy Summit, California Public Utilities Commission and California ISO, San Francisco, California, February 26, 2013.

Fundamental Capacity Market Design Choices: How Far Forward? How Locational? EUCI Capacity Markets Conference, October 3, 2012.

One Day in Ten Years? Economics of Resource Adequacy, Mid-America Regulatory Conference Annual Meeting, June 12, 2012.

Reliability and Economics: Separate Realities? Harvard Electricity Policy Group Sixty-Fifth Plenary Session, December 1, 2011.

National Regulatory Research Institute Teleseminar: The Economics of Resource Adequacy Planning: Should Reserve Margins Be About More Than Keeping the Lights On?, panelist, September 15, 2011.

Improving RTO-Operated Wholesale Electricity Markets: Recommendations for Market Reforms, American Public Power Association Symposium, panelist, January 13, 2011.

Shortage Pricing Issues, panelist, Organization of PJM States, Inc. Sixth Annual Meeting, October 8, 2010.

National Regulatory Research Institute Teleseminar: Forecasting Natural Gas Prices, panelist, July 28, 2010.

Comments on the NARUC-Initiated Report: Analysis of the Social, Economic and Environmental Effects of Maintaining Oil and Gas Exploration Moratoria On and Beneath Federal Lands (February 15, 2010) submitted to NARUC on June 22, 2010.

Forward Capacity Market CONEfusion, Advanced Workshop in Regulation and Competition, 29th Annual Eastern Conference of the Center for Research in Regulated Industries, Rutgers University, May 21, 2010.

One Day in Ten Years? Resource Adequacy for the Smart Grid, revised draft November 2009.

Approaches to Local Resource Adequacy, presented at Electric Utility Consultants' Smart Capacity Markets Conference, November 9, 2009.

One Day in Ten Years? Resource Adequacy for the Smarter Grid, Advanced Workshop in Regulation and Competition, 28th Annual Eastern Conference of the Center for Research in Regulated Industries, Rutgers University, May 15, 2009.

Resource Adequacy in Restructured Electricity Markets: Initial Results of PJM's Reliability Pricing Model (RPM), Advanced Workshop in Regulation and Competition, 27th Annual Eastern Conference of the Center for Research in Regulated Industries, Rutgers University, May 15, 2008.

Statement at Federal Energy Regulatory Commission technical conference, Capacity Markets in Regions with Organized Electric Markets, Docket No. AD08-4-000, May 7, 2008.

Raising the Stakes on Capacity Incentives: PJM's Reliability Pricing Model (RPM), presentation at the University of California Energy Institute's 13th Annual POWER Research Conference, Berkeley, California, March 21, 2008.

Raising the Stakes on Capacity Incentives: PJM's Reliability Pricing Model (RPM), report prepared for the American Public Power Association, March 14, 2008.

Comments on GTN's Request for Market-Based Rates for Interruptible Transportation, presentation at technical conference in Federal Energy Regulatory Commission Docket No. RP06-407, September 26-27, 2006 on behalf of Canadian Association of Petroleum Producers.

Comments on Policies to Encourage Natural Gas Infrastructure, and *Supplemental Comments on Market-Based Rates Policy For New Natural Gas Storage,* State of the Natural Gas Industry Conference, Federal Energy Regulatory Commission Docket No. AD05-14, October 12, 26, 2005.

After the Gas Bubble: A Critique of the Modeling and Policy Evaluation Contained in the National Petroleum Council's 2003 Natural Gas Study, with K. Costello and H. Huntington, presented at the 24th Annual North American Conference of the USAEE/IAEE, July 2004.

Comments on the Pipeline Capacity Reserve Concept, State of the Natural Gas Industry Conference, Federal Energy Regulatory Commission Docket No. PL04-17, October 21, 2004.

Southwest Natural Gas Market and the Need for Storage, Federal Energy Regulatory Commission's Southwestern Gas Storage Technical Conference, docket AD03-11, August 2003.

Assessing Market Power in Power Markets: the "Pivotal Supplier" Approach and Variants, presented at Electric Utility Consultants' Ancillary Services Conference, November 1, 2001.

Scarcity and Price Mitigation in Western Power Markets, presented at Electric Utility Consultants' conference: What To Expect In Western Power Markets This Summer, May 1-2, 2001.

Market Power: Definition, Detection, Mitigation, pre-conference workshop, with Scott Harvey, January 24, 2001.

Market Monitoring in the U.S.: Evolution and Current Issues, presented at the Association of Power Exchanges' APEx 2000 Conference, October 25, 2000.

Ancillary Services and Market Power, presented at the Electric Utility Consultants' Ancillary Services Conference (New Business Opportunities in Competitive Ancillary Services Markets), Sept. 14, 2000.

Market Monitoring Workshop, presented to RTO West Market Monitoring Work Group, June 2000.

Screens and Thresholds Used In Market Monitoring, presented at the Conference on RTOs and Market Monitoring, Edison Electric Institute and Energy Daily, May 19, 2000.

The Regional Transmission Organization's Role in Market Monitoring, report for the Edison Electric Institute attached to their comments on the FERC's NOPR on RTOs, August, 1999.

The *Independent System Operator's Mission and Role in Reliability*, presented at the Electric Utility Consultants' Conference on ISOs and Transmission Pricing, March 1998.

Independent System Operators and Their Role in Maintaining Reliability in a Restructured Electric Power Industry, ICF Resources for the U. S. Department of Energy, 1997.

Rail Transport in the Russian Federation, Diagnostic Analysis and Policy Recommendations, with V. Capelik and others, IRIS Market Environment Project, 1995.

Telecommunications in the Russian Federation: Diagnostic Analysis and Policy Recommendations, with E. Whitlock and V. Capelik, IRIS Market Environment Project, 1995.

Russian Natural Gas Industry: Diagnostic Analysis and Policy Recommendations, with I. Sorokin and V. Eskin, IRIS Market Environment Project, 1995.

Russian Electric Power Industry: Diagnostic Analysis and Policy Recommendations, with I. Sorokin, IRIS Market Environment Project, 1995.

PROFESSIONAL ASSOCIATIONS

United States Association for Energy Economics

Natural Gas Roundtable

Energy Bar Association

May 2019

I/A
W1-2

Wilson Exhibit B

Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing

James F. Wilson, Wilson Energy Economics

Prepared on behalf of the Southern Environmental Law Center

February 12, 2019

I. INTRODUCTION AND SCOPE OF THIS REPORT

1. Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, "Companies" or "Duke") filed their 2018 Integrated Resource Plans ("2018 IRP") on September 5, 2018 in Docket No. E-100 Sub 157. The Companies filed their proposed Avoided Cost tariffs ("2018 Avoided Cost Filing") on November 1, 2018 in Docket No. E-100 Sub 158. The 2018 IRPs present load forecasts (Chapter 3) and recommended reserve margins (Chapter 8) that serve as the basis for each utility's determination of the total generating capacity required over the IRP planning horizon. This capacity need is reflected in the capacity values for solar resources (IRP Chapter 9).

2. The reserve margins used in the 2018 IRPs were based upon recommendations from resource adequacy studies ("DEC 2016 RA Study", "DEP 2016 RA Study"; collectively "2016 RA Studies") that were prepared for DEC and DEP by Astrapé Consulting in 2016, and were also used for the DEC and DEP 2016 IRPs. The capacity values for solar resources were based on an Astrapé report[1] that employs the same model and many of the same assumptions that were used in the 2016 RA Studies. The 2018 Avoided Cost Filing proposes new Schedule PP avoided capacity credits with modified seasonal and hourly structures based on the Astrapé analyses.

3. In a report filed on February 17, 2017 in Docket No. E-100 Sub 147 ("Wilson 2017 RM Report"), I reviewed and evaluated the 2016 RA Studies, raising a number of issues with the Studies' assumptions and methodologies. In this current report I re-

---

[1] Response to Data Request SACE/NRDC/Sierra Club 1-28, *Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study*, August 27, 2018 ("Capacity Value Study").

evaluate the reserve margins used in the 2018 IRPs and the 2016 RA Studies that formed the basis for them with the benefit of additional analysis and data that have become available since the Wilson 2017 RM Report. I also comment on the implications of the various shortcomings in the 2016 RA Studies and the related Capacity Value Study for the projection of seasonal loss of load risk, seasonal capacity values, and avoided cost rate design. The focus in this report is on demand-side assumptions, including load patterns and demand response; supply-side assumptions, including solar modeling, were outside the scope of this report. The load forecasts used in the 2018 IRPs are the subject of a separate Wilson Energy Economics report.

II. BACKGROUND

4. In its final order on the 2016 IRPs, the North Carolina Utilities Commission ("NCUC" or "Commission") concluded that the proposed reserve margins included in the 2016 IRPs were "reasonable at this time for planning purposes", but also concluded that the proposed move to a 17% winter reserve margin target was "not supported by the evidence."[2] The order called for DEC and DEP to work with the Public Staff to address the concerns raised by the Public Staff and in the Wilson 2017 RM Report, and to "implement changes as necessary to help ensure that the reserve margin target(s) are fully supported in future IRPs."

5. In its final order in the 2016 avoided cost docket, the Commission accepted Duke's proposed seasonal capacity weighting of 80% winter and 20% summer for determining the avoided capacity rates, noting that the proposal relied upon the 2016 RA Studies, and stating that the Commission would be receptive to revisiting the seasonal capacity weighting in future avoided cost cases.[3]

---

[2] *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans*, Docket No. E-100, Sub 147, June 27, 2017 at 21-22.

[3] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, Docket No. E-100, Sub 148, October 11, 2017 at 59.

6. On April 2, 2018 in the 2016 IRP docket, the Public Staff filed a joint report of the Public Staff, DEC and DEP addressing the reserve margin issues ("Joint Report"), to which was attached a Duke presentation to the Public Staff: *2016 Resource Adequacy Study – Outstanding Issues*, December 12, 2017 ("December 2017 Presentation"). In an order issued April 16, 2018, the Commission accepted the Joint Report, noting that the Public Staff and DEC and DEP did not reach consensus on all of the issues they discussed. The Companies' views on these issues were also reflected in their May 10, 2017 Reply in the same docket.

III. SUMMARY AND RECOMMENDATIONS

7. Both 2018 IRPs recommend a 17% winter planning reserve margin (p. 8), based on the 2016 RA Studies (p. 6), which is an increase relative to the reserve margins used before the 2016 IRPs. The Avoided Cost Filing proposes a 100%/0% winter/summer capacity payment weighting for DEP, and 90%/10% for DEC, citing to the 2018 IRPs (Table 9-B), which recommendation is also based on the 2016 RA Studies and related Capacity Value Study. (p. 29) These recommendations are based on analysis that attempts to reflect the recent experience with extreme cold temperatures and also higher solar penetration (2018 IRP, p. 38).

8. The evaluation performed for this report focused on the following issues with regard to the 2016 RA Studies and Capacity Value Study:

a. The representation of some very extreme winter loads, based on an extrapolation of the relationship between cold temperatures and winter loads;

b. The "economic load forecast uncertainty" layered on top of the weather-related load distributions;

c. The assumptions regarding future winter demand response capacity; and

d. The assumptions regarding operating reserves during brief load spikes on extremely cold winter mornings.

9. This report shows that the risk of very high loads under extreme cold was substantially overstated in the 2016 RA Studies, primarily due to the faulty approach to extrapolating the increase in load due to very low temperatures. Winter resource adequacy risk was also overstated due to the demand response and operating reserve assumptions applicable to winter peak conditions. Overall, the winter resource adequacy risk was substantially overstated relative to the risk in summer and other periods of the year. Accordingly, the winter/summer capacity values of solar resources proposed for use in the 2018 IRPs (Tables 9-B and 9-C, pp. 45-46), as well as the avoided capacity cost weightings (100%/0%, 90%/10%) proposed for use in the Companies' Schedule PP filed in Docket No. E-100, Sub 158, should be rejected, and much more balanced seasonal weights developed and approved.

10. Both winter and summer risk were further overstated due to the economic load forecast uncertainty assumptions, which greatly overstate the risk of large and unexpected increases in peak load. Due to this error as well as the overstatement of winter resource adequacy risk, I again conclude that the recommended increases in the DEC and DEP reserve margins (relative to IRPs before 2016) are unsupported and unnecessary.

11. I also note that the Companies' approach to estimating seasonal, monthly and hourly resource adequacy risk, seasonal capacity values of solar resources, and recommended reserve margins will be highly sensitive to various assumptions that can change dramatically over just a few years. This suggests that a fixed rate design, such as reflected in Schedule PP, should not be overly focused on relatively few months of the year or hours of the day, because the Companies' estimates of the seasons and hours with resource adequacy risk can change over time as load shapes and the resource mix change. Additionally, the price signals inherent in the rate design can shifts capacity needs to adjacent hours or months. While it is important to strive for accurate price signals, it is also important to strive for price signals that are reasonably stable over time, and likely to remain reasonably accurate as conditions change. Because the Companies' proposed Schedule PP rate designs are based on the same flawed analysis that is highly

sensitive to assumptions, I also recommend rejecting the proposed monthly and hourly rate structures.

12. I do not recommend specific seasonal weightings, monthly and hourly rate structures, or reserve margins, as this would require use of the Companies' modeling tools to perform further analysis with the flaws identified above corrected.

13. The analysis documented in this report was again hampered by incomplete responses to some data requests and a lack of details and sensitivity analyses with regard to the 2016 RA Studies. Appendix A to this report further discusses the importance of access to the full details of such analyses, and provides recommendations for future IRPs.

14. The remainder of this report is organized as follows. Section IV discusses the four issues with the 2016 RA Studies and Capacity Value Study that overstate winter risk and required reserve margins. Section V summarizes findings and recommendations, including recommendations for future IRPs. Appendix A lists additional information that was sought but not provided. Appendix B summarizes the author's qualifications.

IV. CRITIQUE OF THE 2016 RA STUDIES AND CAPACITY VALUE STUDY

15. The 2016 RA Studies document a probabilistic simulation of load and resources to find the planning reserve margin required to satisfy a "one day in ten years" ("1-in-10") resource adequacy criterion, equivalent to an annual Loss of Load Expectation ("LOLE") of 0.1 events per year. The Capacity Value Study applies the same model logic and load modeling methodology, and many other common assumptions, to evaluate various levels of solar penetration.[4] The 2016 RA Studies and Capacity Value Study determine certain months and hours of the year in which risk of loss of load occurs, according to the specific assumptions used in each study.

[4] Response to Data Request SACE/NRDC/Sierra Club 4-6.

A. REPRESENTING THE IMPACT OF EXTREME COLD ON WINTER PEAK LOADS

16. In recent years, brief periods of extreme cold have resulted in very high loads on the DEC and DEP systems. To accurately evaluate winter period resource adequacy, it was appropriate for the 2016 RA Studies to model extreme cold and its impact on load levels. The same representation of load was used in the Capacity Value Study.

17. In the winters of 2014 and 2015 there were a few days colder than any that had occurred in the DEC and DEP-East service territories since 1996. Based on the temperature data used for the DEC RA Study,[5] 2014 and 2015 each had two days in which temperatures dropped below 10 degrees Fahrenheit; in the years before 2014, temperatures had not dropped to even 11 degrees since 1996. However, the 2016 RA Studies used 36 years of historical weather data, back to 1980, and even lower temperatures were seen in some years in the 1980s (3, 4, and 5 degrees in 1982, 1983, and 1986, respectively, and minus 5 in 1985). Therefore, to use 36 years of weather data it was necessary to model loads under temperatures below any that had been seen in the last 30 years.

18. The 2016 RA Studies determined load levels under extreme cold conditions applying a very simple regression analysis to recent data.[6] The regressions consider only temperature (not wind speeds), and focus on temperatures in the 18-25 degree range (DEP East; 18-22 for DEC), for which observations are plentiful. Based on the regression, the DEC RA Study estimated the DEC load, under extreme cold conditions, with the following linear equation:

DEC Load (MW) = -231 * (Temperature) + 20,372.

19. This equation implies that under extreme cold conditions, for each degree the temperature falls, DEC's load is assumed to increase by 231 MW (roughly 1.3%). Four

[5] Response to Data Request NCSEA 3-12 in Docket No. E-100 Sub 158.

[6] Response to Data Request SACE/NRDC/Sierra Club 3-1 attachment. This attachment includes the original regressions from the 2016 RA Studies.

additional degrees results in 924 MW of additional load (over 5% increase). A similar equation was derived for DEP East loads, that suggested 228 MW per degree.

20. The Wilson 2017 RM Report criticized this approach, providing analysis showing that for lower temperatures, the relationship between temperature and load was much weaker than this equation suggests. This is logical -- once temperatures drop to the teens, customers may have turned on all of the equipment that will help them stay warm, and further declines in temperature do not increase loads as much. In addition, some schools, offices, and other commercial, government and industrial facilities may close, reduce operations, or open late due to extreme cold conditions, reducing loads during the morning peak.

21. The fact that beyond some point further cold does not have as great an impact on load was quantified in Figures JFW-1 and JFW-2 in the Wilson 2017 RM Report. In particular, the analysis shown in Figure JFW-1 of that report showed that for temperatures under 17 degrees, DEC load only increased 108 MW, not 231 MW, for each additional degree.

22. The Joint Report did not address the inaccuracy of the regressions used in the 2016 RA Studies. The Joint Report notes the issue of the regression equations, and then states, "After meeting with the Company, the Public Staff was satisfied that this approach was reasonable." (p. 2)

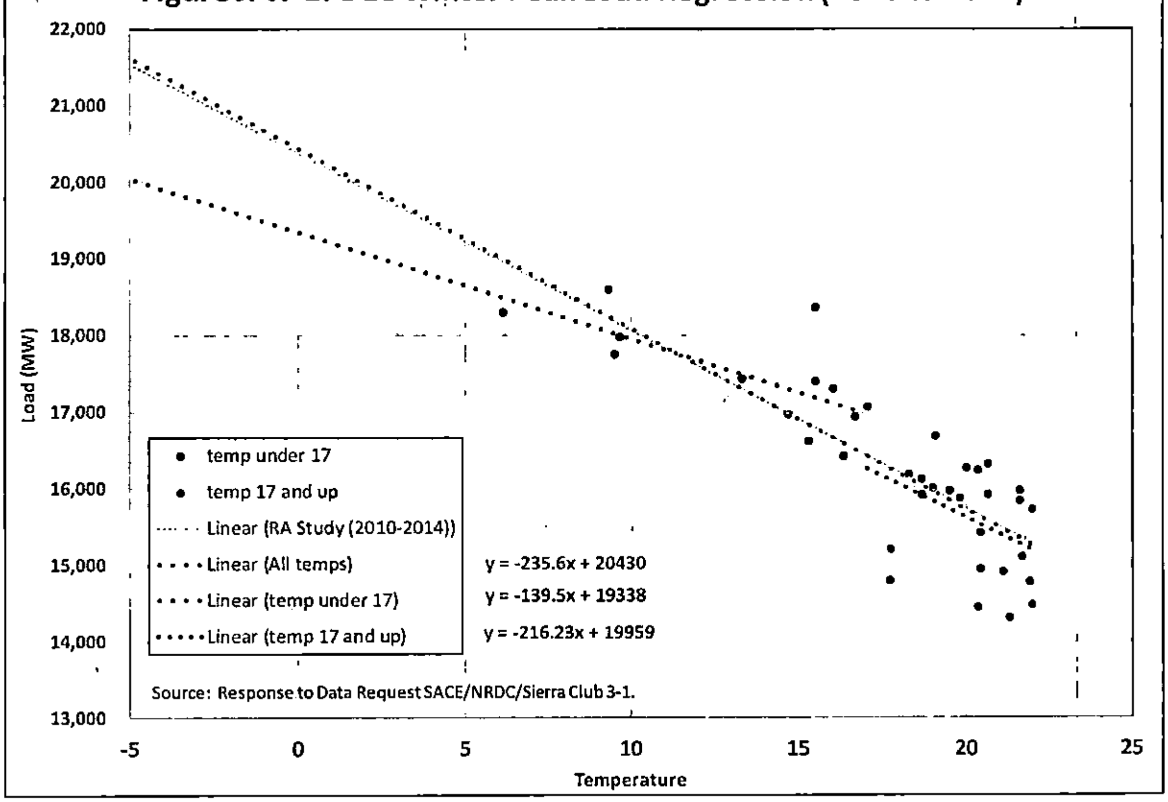
23. The December 2017 Presentation that was attached to the Joint Report claimed that "use of more current data would suggest a similar load response to temperature" for both DEC and DEP. (pp. 11-12) However, with the additional data, it also remains true that the impact of extreme cold on load is much weaker at lower temperatures, so the regressions used in the RA Studies are inaccurate for lower temperatures.

24. The regressions for the 2016 RA Studies were based on data from 2010 through 2014; for the December 2017 Presentation, data for 2015, 2016 and 2017 was

added.[7] The Companies' updated regressions, now with data through 2017, produce similar results to those in the 2016 RA Studies.

25. I updated the analysis I performed in the Wilson 2017 RM Report using this updated data set, and got very similar results – the relationship between extreme cold and load is much weaker for the lower temperatures. The results are shown in Figures JFW-1 and JFW-2. For DEC, across the entire temperature range, the relationship suggests 235.6 MW of additional load per degree, as shown in the green line in Figure JFW-1 and its regression equation. However, for temperatures below 17 degrees, the relationship is only 139.5 MW per degree (red line and equation). And it is likely that even this value (139.5 MW per degree) overstates the impact of the most extreme temperatures on loads, when, as suggested above, space heating appliances are already in full use and some facilities are remaining closed or opening late.

Figure JFW-1: DEC Winter Peak Load Regression (2010 to 2017)

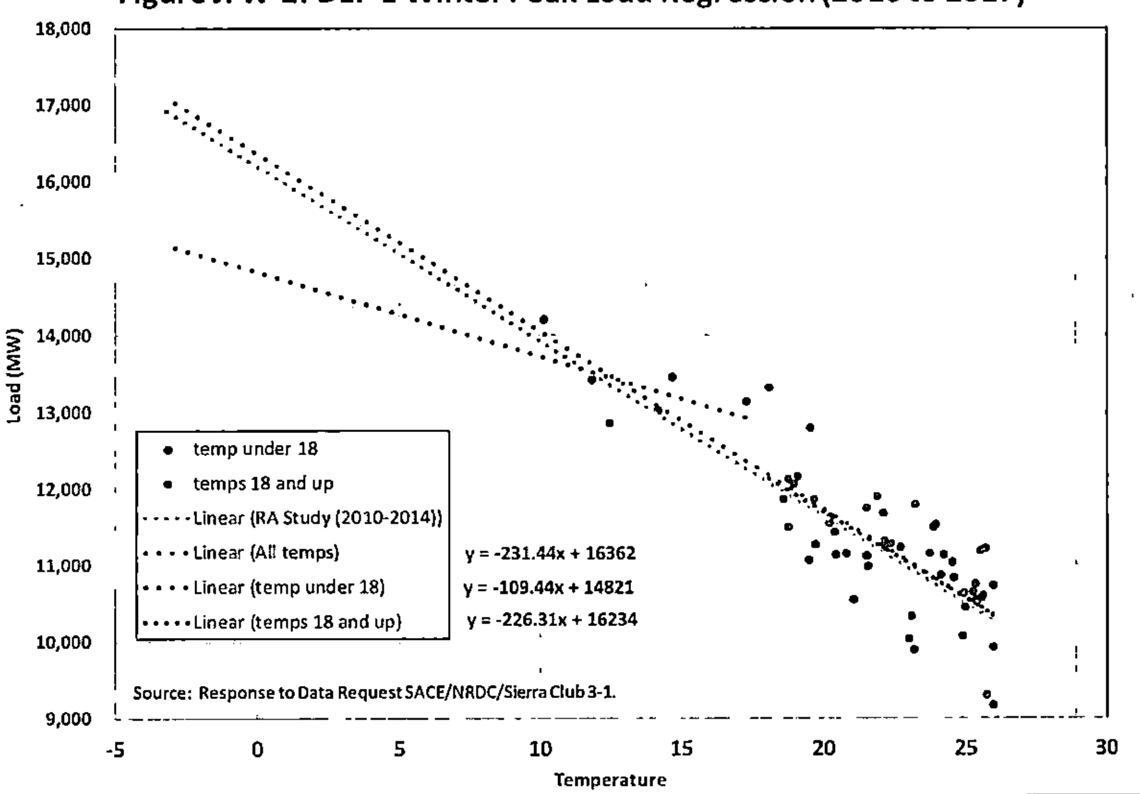


[7] Response to Data Request SACE/NRDC/Sierra Club 3-1 attachment.

26. The 36-year data set used in the DEC RA Study includes temperatures as low as minus 5 degrees. As the trend lines in Figure JFW-1 suggest, extrapolating based on all observations (green and yellow lines) leads to over 21,500 MW at minus 5 degrees, while extrapolating based on temperatures below 17 degrees (red line) leads to an estimated 20,000 MW load (which is probably still too high). I again conclude that the DEC RA Study greatly overstates loads under extreme cold conditions. This has a substantial impact on the DEC RA Study – of the simulated hours with load loss, most result from scenarios under which the winter extrapolated load exceeded 20,000 MW, even before the economic load forecast uncertainty was reflected.[8]

27. Figure JFW-2 presents the updated analysis for DEP East, which leads to the same conclusion (the red line and equation) – after a point, as temperatures drop further, the impact on load is much weaker. Compared to over 200 MW per degree for

Figure JFW-2: DEP E Winter Peak Load Regression (2010 to 2017)



[8] Response to Data Request SACE/NRDC/Sierra Club 1-26 attachment (discussed below).

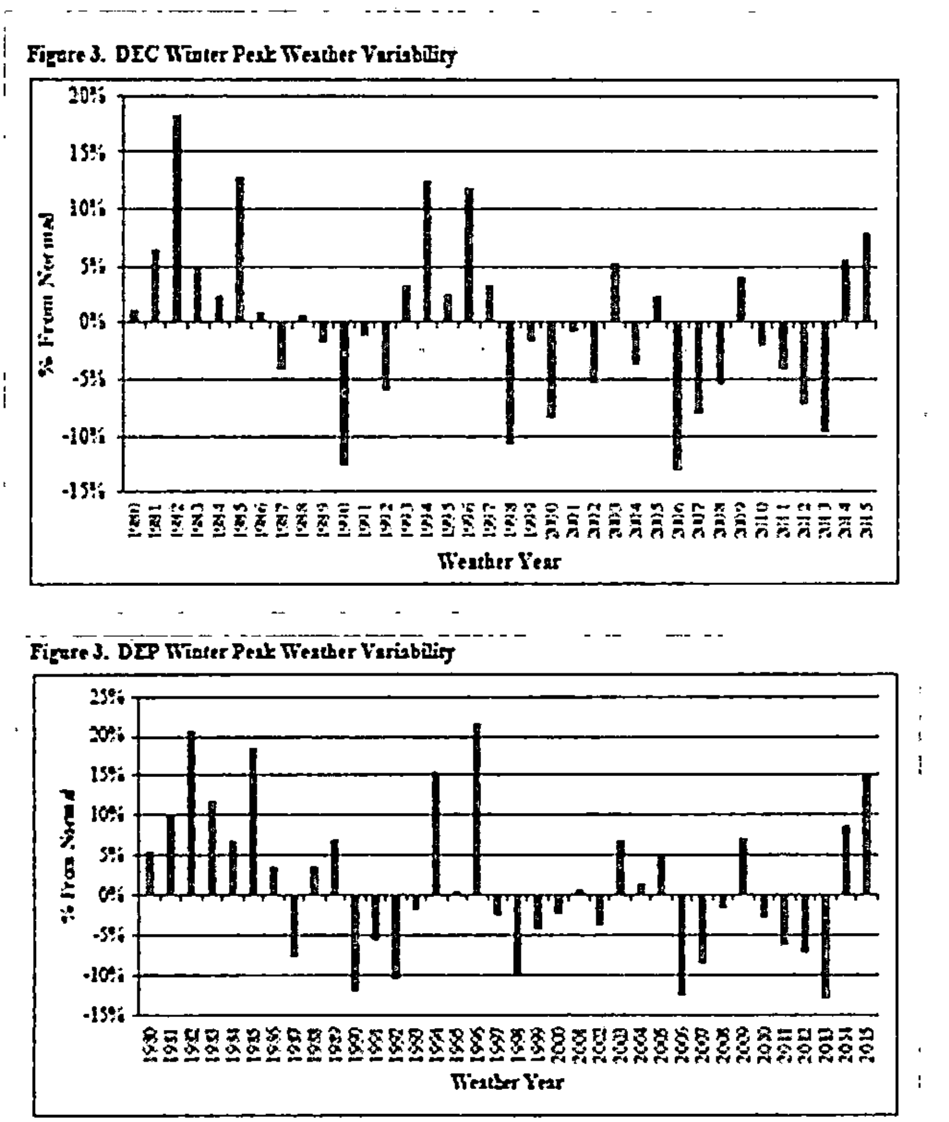
temperatures in the 20s, below 18 degrees the relationship is 109.4 MW per degree. Again, the impact would likely be even weaker at lower temperatures, if data were available, so even 109.4 MW per degree likely results in overstating the loads at the lowest temperatures.

28. The 36-year data set used in the DEP RA Study includes temperatures below minus 3 degrees for DEP East. As the trend lines in Figure JFW-2 suggest, extrapolating based on all observations (green and yellow lines) leads to 17,000 MW at minus 3 degrees, while extrapolating based on temperatures below 18 degrees (red line) leads to just over 15,000 MW (which is probably still too high). In the DEP RA Study, two-thirds of the simulated hours with load loss were based on winter extrapolated loads in excess of 15,000 MW.[9] I again conclude that the DEP RA Study greatly overstates loads under extreme cold conditions.

29. The 231 MW per degree assumption for DEC, and 228 MW per degree assumption for DEP East, used in the 2016 RA Studies resulted in some very extreme peaks under the very cold conditions represented in some of the 36 weather years. Figure JFW-3 shows figures from the 2016 RA Studies illustrating how high winter peaks are assumed to go, as a result of the regression equations. While the extreme cold in 2014 and 2015 resulted in extreme peak loads roughly 5% to 8% above the anticipated, normal winter peak loads in those years, the 231 MW per degree assumption for DEC results in modeling peaks in the 1982 weather year 18% above the anticipated winter peak (for 2019, the year that is the focus of the 2016 RA Studies, 18% equates to over 3,300 additional MW). Modeling such extreme peaks will, of course, drive the winter reserve margin higher, and increase winter resource adequacy risk relative to summer risk. Using more realistic estimates would bring these extreme peaks down considerably. Figure JFW-3 also shows the similar graphic from the DEP RA Study, which also reflects very extreme winter peaks (over 20% above the normal winter peaks) based on the unrealistic estimates of the relationship between extreme cold and load. Figure JFW-3 also shows

[9] Response to Data Request SACE/NRDC/Sierra Club 1-26 attachment.

Figure JFW-3: Figure 3 from the DEC and DEP RA Studies



that the highest loads modeled in the 2016 RA Studies correspond to two instances in the 1980s and two in the 1990s; the 2014 and 2015 events are moderate in comparison.

30. Through discovery, the Companies provided data showing the scenarios (weather year, day, hour, load forecast error assumption), that led to lost load in the 2016 RA Studies.[10] For DEP, using all years, the RA Study has 86% of the expected load loss hours in winter; if only weather data 1997 and later is used, 75% of the load loss hours

[10] Response to Data Request SACE/NRDC/Sierra Club 1-26 attachment.

are in summer and only 25% are in winter. For DEC, 69% of the expected load loss hours are in winter in the RA Study; but if only weather since 1997 is modeled, 92% of the load loss hours are in summer, 8% are in winter. This data shows that in the RA Studies, the vast majority of the hours with load loss result from scenarios based on those instances of extreme cold from the 1980s and 1990s, and the overstated loads associated with them due to the flawed regressions. While including more rather than less historical weather data is preferred, excluding the 1982-1996 data quantifies how the flawed regressions have skewed the results and overstated winter resource adequacy risk. The data strongly suggest that if the regressions were corrected, the resource adequacy risk would still be weighted toward summer on both systems.

31. Thus, the vast majority of the winter LOLE in the 2016 RA Studies is based on a highly simplified and inaccurate assumption about how loads would increase due to extreme temperatures, applied to temperatures that have not been seen in decades. These assumptions, which were new in the 2016 RA Studies, drove the winter risk and reserve margins very high.

32. The inaccuracy of the extrapolation equations used in the 2016 RA Studies was raised in the Wilson 2017 RM Report, but neither the Joint Report nor the December 2017 Presentation substantively addressed this issue.[11] The additional three years of data included in the updated data set provide further support for the conclusion that the extrapolation greatly overstated loads under the most extreme temperatures.

33. The regressions used in the 2016 RA Studies are also flawed in that they did not consider wind speeds, which also have a substantial impact on loads. Figures JFW-1 and JFW-2 suggest that the relationship between temperature and load is not that strong; for example, Figure JFW-1 shows that temperatures in the low 20s have resulted in loads around 14,300 MW, but on other days such temperatures have resulted in loads about 2,000 MW higher. One approach to reflecting the impact of wind speeds is to calculate a "wind chill" measure that combines temperature and wind into a single

[11] Response to Data Request SACE/NRDC/Sierra Club 1-23(a) (stating that slides in the December 2017 Presentation are the only response to the Wilson 2017 RM Report's critique of the regressions).

parameter. For example, the regional transmission organization PJM Interconnection, L.L.C. ("PJM") utilizes a "Winter Weather Parameter" in its winter load forecasting. The equation for the Winter Weather Parameter suggests that for winds in excess of 10 MPH, each 10 MPH of wind speed is equivalent to 5 additional degrees of cold.[12]

34. While not addressing the inaccuracy of the regressions, the Joint Report did provide information showing the substantial impact of even small changes to the regressions on the 2016 RA Study results. As a sensitivity case for DEC, the impact of colder temperature on load was reduced by 50% for the very few instances of temperatures below 6 degrees (7 days during 1982 to 1996; none have occurred since). This was estimated to reduce the reserve margin by 0.33%.[13] That's a substantial impact on the reserve margin and winter resource adequacy risk; but this sensitivity analysis falls far short of addressing the inaccuracy of the regressions. As the trend lines in Figure JFW-1 show (comparing the green to the red line), the DEC RA Study overstates loads by about 500 MW at 6 degrees, increasing to about 1,500 MW at the lowest temperatures. This sensitivity case used the flawed regression equation for loads at 6 degrees and higher temperatures, and made small changes for temperatures in the 4 to 6 degree range. The adjustment in the sensitivity case exceeded 100 MW for only four days, and exceeded 400 MW on only one day.[14] Yet this minor adjustment was estimated to have a 0.33% impact on the reserve margin. More completely correcting the regressions (for example, by using the red trend lines shown in Figures JFW-1 and JFW-2 for temperatures below about 11 degrees) would have a much larger impact on the reserve margin, and would also substantially reduce winter resource adequacy risk.

[12] PJM Manual 19 *Load Forecasting and Analysis* rev. 33, October 25, 2018, pp. 13-14, available at https://www.pjm.com/-/media/documents/manuals/m19.ashx.

[13] Response to Data Request SACE/NRDC/Sierra Club 4-11, attachment slide 7.

[14] Response to Data Request SACE/NRDC/Sierra Club 4-11, attachment slide 3.

B. Representing Economic Load Forecast Error

35. If peaks loads grow faster than forecasted (for example, due to stronger than expected economic growth), it could result in actual reserve margins lower than were anticipated in resource plans published years in advance. The 2016 RA Studies include "economic load forecast error," intended to represent the possible error in four-year-ahead load forecasts (DEC RA Study, p. 16). This resulted in modeling scenarios under which the peak was under-forecast by 4%, with no supply-side adjustments. This assumption had a substantial impact on the reserve margins: if the analysis instead uses the lower error reflected in one-year ahead load forecasts, the reserve margin declines by about 1%.[15]

36. The Wilson 2017 RM Report criticized the representation of economic load forecast uncertainty on two grounds. First, it explained why it was not appropriate to include *multi-year* economic load forecast uncertainty in the 2016 RA Studies, because the model used was unable to represent the short-lead-time actions that the Companies and market participants would take if stronger-than-expected load growth were to materialize and continue year after year. Second, the Wilson 2017 RM Report explained that the probability distribution of economic load forecast error used in the 2016 RA Studies was not supported by the underlying data it was based upon, and greatly overstated the risk of large unexpected increases in peak load.

37. The Public Staff criticized the same two aspects of the representation of load forecast uncertainty (multi-year, and probabilities assigned to large under-forecast).[16] In the Joint Report, the Public Staff stated (p. 10) that it believes the approach to load forecast uncertainty used in the 2016 RA Studies is "problematic and will likely result in an incorrect calculation." In its comments in the Joint Report, the Companies evaluated and criticized the Public Staff's specific proposal for representing load forecast

---

[15] December 2017 Presentation, slide 27.

[16] Joint Report pp. 9-11.

uncertainty. Rejecting the Public Staff's proposal, and failing to address my criticisms, the Companies then supported the assumptions used in the 2016 RA Studies.[17]

38. The December 2017 Presentation rationalized using multi-year economic load forecast uncertainty as follows: "Given that it takes 3-5 years to put new generation infrastructure in place, the Companies and Astrapé believe that 3 years of economic load growth uncertainty is appropriate."[18] However, as explained in the Wilson 2017 RM Report, this ignores the fact that there are many short lead time actions that can and very likely would be taken. If load grows faster than expected, the utilities (and customers and other market participants too) would have time to adjust their plans, if the rate of load growth raised concern about resource adequacy. To name a few potential actions, the development of some new resources might be accelerated; demand response or energy efficiency programs could be increased; a planned retirement could be delayed; firm purchases from adjacent regions could be adjusted; or wholesale sales contracts could be allowed to expire.

39. The 2016 RA Studies essentially assume the reserve margin and resource plan must be chosen over three years in advance, and then the resource plan must remain frozen, even if load growth is much stronger than expected year after year.[19] This is not realistic, and is at odds with the Companies' business practices, including the biannual IRP planning cycle. The assumption that load can rise sharply and unexpectedly, but no adjustments to the resource mix can or would be made over three years, biases the planning reserve margin upward.

40. It is notable that PJM, in its resource adequacy analyses, acknowledges that resource plans can and would be adjusted as needed if load grows faster than expected. Accordingly, while PJM's resource adequacy analysis focuses on determining

[17] Joint Report pp. 21-24; December 2017 Presentation, slides 21-27.

[18] See also response to Data Request SACE/NRDC/Sierra Club 4-10.

[19] This was confirmed in the responses to Data Requests SACE 2-22 and 2-23 in Docket No. E-100 Sub 147.

planning reserve margins for peaks over three years into the future, PJM represents only one year of economic load forecast error in its analyses.[20]

41. The Wilson 2017 RM Report also noted that it could be appropriate to represent multiple years of forecast uncertainty in a more sophisticated model that is able to internally determine supply-side or demand-side adjustments over time as the load forecast and other resources change over time. For instance, the Electric Power Research Institute's Over/Under capacity planning model, developed in the 1970s, had this capability.[21] Planning reserve margins for future years are somewhat smaller if it is recognized that supply plans can be adjusted over time. However, the SERVM model that was used in the 2016 RA Studies does not have the capability to represent any such contingent decisions. To represent multi-year load forecast uncertainty, but not the actions that would be taken to adapt resource planning over time as such uncertainty resolves, is a flawed methodology that biases the result toward higher planning reserve margins. I again conclude that it was inappropriate to use 3-year load forecast uncertainty; it would be more appropriate to use one year (which, as noted, would lower the reserve margin by 1%, even if no other changes were made).

42. Turning to the values used for the economic load forecast error, the economic load forecast uncertainty was represented as a symmetric probability distribution (DEC RA Study Table 4 p. 17). A 7.9% probability was assigned to both +4% and -4% shifts in load, 24% probability was assigned to both +2% and -2% shifts, and 36.3% chance was assigned to no change due to economic load forecast error. Thus, all loads, including the extreme weather-related load levels discussed in the prior section of this report, are increased by an additional 4% under the highest economic load forecast error scenario, and 2% under an additional scenario assigned a 24% probability.

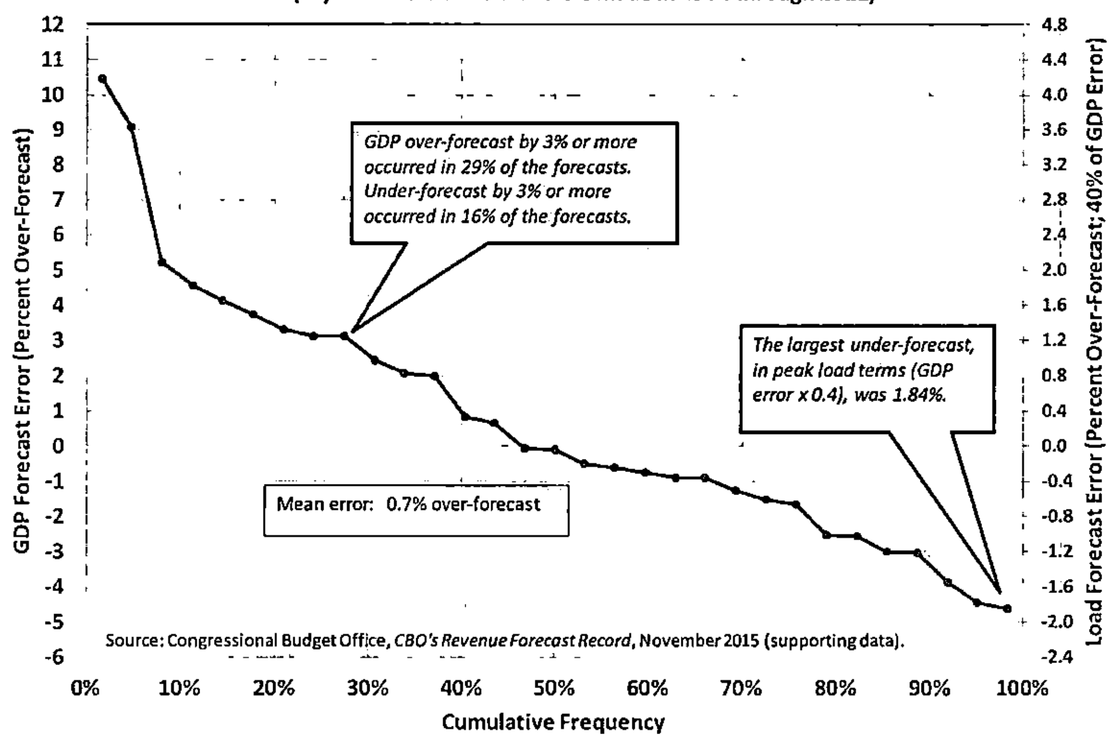
---

[20] See, for instance, PJM, *2012 PJM Reserve Requirements Study*, p. 20 (explaining the rationale for using a forecast error factor representing one year of forecast error).

[21] Decision Focus Incorporated, *Costs and Benefits of Over/Under Capacity in Electric Power System Planning*, EPRI EA-927, Project 1107, October 1978.

43. The DEC RA Study states (pp. 16-17) that the probability distribution was based on the historical forecasting errors reflected in the U.S. Congressional Budget Office ("CBO") U.S. Gross Domestic Product ("GDP") forecasts, and applying a 0.4 elasticity of peak demand to economic changes.[22] The CBO data is readily available, including the CBO's own analysis of its 3-year GDP forecasting errors.[23] Figure JFW-4 presents the full distribution of the 3-year forward GDP forecast errors (left axis), and the corresponding load forecast errors based on the 2016 RA Studies' 0.4 elasticity assumption (right axis).

Figure JFW-4: Distribution of CBO 3-Year GDP Forecast Errors
(3-year forward GDP forecasts made in 1982 through 2012)



[22] It is also questionable whether CBO U.S. GDP forecasting errors are a reasonable proxy for the applicable economic forecasting errors for the North Carolina economy. The DEC and DEP load forecasts rely upon forecasts of the North Carolina economy.

[23] Congressional Budget Office, CBO's Revenue Forecasting Record, November 10, 2015, and Supplemental Data available at https://www.cbo.gov/sites/default/files/114th-congress-2015-2016/reports/50831-RevenueForecasting-SuppData.xlsx. In the response to data request SACE/NRDC/Sierra Club 4-12, Duke provided its own analysis of GDP forecast errors, however, Duke's GDP data are different from the CBO's, and its analysis is also different. No citation was provided for the source of the data Duke used for this analysis.

44. The symmetric load forecast error distribution used in the 2016 RA Studies misrepresents the distribution of CBO forecast errors and associated load forecast errors. The CBO forecast errors are not symmetric, and the under-forecast errors tend to be small. This is not surprising: economic downturns can be sudden, largely unexpected, and sharp, as seen in 2008. Surprisingly strong economic growth, by contrast, would tend to develop and accumulate more slowly over time.

45. The 2016 RA Studies assign almost 32% probability to under-forecast errors whose magnitude (+4% or +2%, in load forecast terms) never occurred even once in 30 years, according to the CBO data the distribution was purportedly based upon. Over the thirty years of CBO data, the largest 3-year GDP under-forecast error was 4.61 percent, which translates (times 0.4) into a load forecast under-forecast of only 1.84%. In contrast, the 2016 RA Studies assign 7.9% and 24% probability to under-forecasting peak load by 4 percent and 2 percent, respectively, as described above. The economic load forecast error distribution used in the 2016 RA Studies misrepresents the CBO data, and greatly overstates the risk of substantial under-forecasting.

46. It is also notable that economic forecasters now expect lower U.S. GDP growth than occurred over the past thirty years, which further shrinks the likelihood of large under-forecasting errors. According to the Federal Reserve Bank of Philadelphia's biannual Livingston Survey of approximately 25 economic forecasters, up until 2006, forecasters expected 3.2 percent per year GDP growth, but more recently the median expectation has been only 2.2 percent per year.[24]

47. It also notable that the Companies have not performed any research that supports the assumed elasticity value of 0.4.[25]

48. The exaggerated representation of load forecast error (inappropriately using multi-year error, and misrepresenting the underlying CBO data) had a substantial impact on the 2016 RA Studies. Of the scenarios with load loss in the RA Study simulations

[24] Federal Reserve Bank of Philadelphia, *Livingston Survey*, December 2018; releases from 1991 to present are available at https://www.philadelphiafed.org/research-and-data/real-time-center/livingston-survey.

[25] Response to Data Request SACE/NRDC/Sierra Club 4-9c.

for DEC, 62% occurred under the +4% load forecast error scenario, and 83% occurred under the +2% and +4% scenarios.[26] For DEP, 51% of the load loss instances were under the +4% scenario, 77% under the +4% and +2% scenarios.

49. Consequently, even accepting the inclusion of multi-year economic forecast errors, and accepting use of the CBO data to develop the distribution, the 2016 2016 RA Studies have misrepresented the distribution of errors, exaggerating the risk of substantial under-forecasting. This exaggeration of the potential for under-forecasting of economic load growth, in addition to the exaggeration of winter peak loads, will further bias the planning reserve margin upward.

C. Demand Response Assumptions

50. Historically, the Companies were summer-peaking, with loss of load risk, and therefore capacity value, concentrated in the summer period.[27] The Companies therefore have designed their demand response programs to reduce demand on the hottest summer days of the year,[28] and, as a result, have had roughly twice as much demand response available in summer as in winter. The 2016 RA Studies assume that demand response will continue to be summer-focused, despite now identifying more resource adequacy risk in winter than in summer. Under more balanced demand response assumptions, the seasonal resource adequacy risk would also be more balanced.

51. The DEC RA Study assumed 1,119 MW of summer demand response and 514 MW of winter demand response. (p. 25) If instead the winter demand response is brought up to the summer level (and everything else remains the same), this eliminates load loss in the winter in the 2016 RA Study to the point where there are now more summer than winter hours with load loss.[29] The DEP RA Study assumes almost twice as

---

[26] Response to Data Request SACE/NRDC/Sierra Club 1-26 attachment.

[27] See, for instance, *Duke Energy Carolinas 2012 Generation Reserve Margin Study*, p. 14; response to Data Request SACE/NRDC/Sierra Club 4-1c.

[28] Response to Data Requests NCSEA 3-36, 3-37.

[29] Response to Data Request SACE/NRDC/Sierra Club 1-26 attachment.

much demand response in summer than in winter -- 926 MW to 496 MW. (p. 25) But if winter demand response is expanded by 900 MW (which, if DEP believes risk is mainly in the winter, it should definitely pursue), most of the hours with load loss would be in the summer.

52. This shows that the conclusion that the risk of load loss is concentrated in the winter is not only greatly exaggerated due to the flaws discussed earlier in this report, it is also highly sensitive to particular resource mix assumptions, such as demand response, that can and should be adjusted for the future. The Companies' 2016 analysis shows that the technical and economic potential for residential winter demand response exceeds 2,300 MW for both DEC and DEP.[30] Yet the Companies are not considering any changes to their demand response programs at this time.[31]

D. Operating Reserve and Load Following Assumptions

53. The 2016 RA Studies also exaggerate winter risk through the operating reserve assumptions. The model used in the DEC RA Study (p. 25) sets aside 716 MW for operating reserve and regulation, plus 1.5% of load (approximately 300 MW) for load following, in all hours, for a total of over 1,000 MW (for DEP, the corresponding number is about 750 MW).

54. For both DEC and DEP, about 60% of the annual load loss hours in the 2016 RA Studies occur on the brief (and, as explained above, overstated) load spikes on very cold winter mornings, with the majority of these outages lasting one or two hours.[32] During these very brief winter morning load spikes, the system operators know that loads will soon decline and that such a substantial amount of reserve is not needed at that time. Accordingly, the system operators would very likely choose to go somewhat short on these reserves rather than call for firm load curtailment. The modeling assumption that

[30] Response to Data Request SACE/NRDC/Sierra Club 4-16 attachment, *Duke Energy North Carolina DSM Market Potential Study,* prepared by Nexant for Duke Energy, December 19, 2016, pp. 47, 50, 62, 71.

[31] Response to Data Requests NCSEA 3-38, 3-39.

[32] Response to Data Request SACE/NRDC/Sierra Club 1-26 attachment.

this large amount of resource would be held, causing firm load curtailment, further exaggerates the risk of load loss on winter mornings in the 2016 RA Studies. By contrast, the summer peaks typically occur over multiple hours with load levels changing relatively slowly, so the adopted operating reserve assumptions are more justified for the summer period.

55. In the DEC RA Study, if it is assumed that the system operators would allow the over 1,000 MW set aside as operating reserve and load following to briefly fall by 500 MW during the brief winter morning load spikes, the instances of winter load loss would be fewer than in summer.[33]

E. Model Estimates of Seasonal and Hourly Capacity Value Are Highly Sensitive to Assumptions That May Change

56. The estimates of the particular seasons, months, and hours where the risk of load loss is highest, based on the modeling approach documented in the 2016 RA Studies and similar Capacity Value Study, will be highly sensitive to various model assumptions that can change over time. Assumptions about the penetration of seasonal resources such as wind, solar and demand response can shift the seasonal balance, and also shift the particular hours in which capacity is likely to be scarce. Tailored demand response programs, or energy storage capacity (such as storage associated with solar resources) can shave peaks or shift them to adjacent hours. Load shapes may also change, due to the penetration of new end-use technologies, or changes in customers' habits, such as usage of programmable thermostats. Various scenarios of these assumptions might suggest very different seasonal and hourly patterns for the modeled load loss.

57. The Companies' methodology is to identify certain seasons, months, and hours, and assign capacity value to those time periods, based on such model runs.[34] The winter/summer weights, mentioned earlier, are highly weighted toward winter, which, as

[33] Response to Data Request SACE/NRDC/Sierra Club 1-26.

[34] The details are in a confidential response to Data Request NC Public Staff 6-2 in Docket No. E-100, Sub 158.

explained above, is based on flawed analysis. Correcting those flaws would shift resource adequacy risk back toward summer, as would higher penetration of winter demand response or wind resources, which tend to have higher output during winter peaks than summer peaks.

58. A more balanced seasonal weighting is also suggested by the simple fact that the vast majority of high load hours are in summer on both systems. According to DEC's load forecast, 83% of the highest load hours (top 1%) are in summer; for DEP's load forecast, 74% of the top 1% load hours are in summer. [35]

59. DEC's proposed Schedule PP proposes summer capacity credit only in the months of July and August from 4 to 8 PM. Both companies propose winter capacity credit for six hours per day, 6 to 9 AM and 6 to 9 PM. DEC's proposed Schedule PP sets a capacity credit more than three times higher for winter mornings than for winter evenings; DEP's winter morning rate is more than twice the winter evening rate. But the modeling that determined these particular schedules as well as the high ratios is also highly sensitive to various assumptions about load shapes, customer habits, and demand response.

V. SUMMARY AND RECOMMENDATIONS

60. This evaluation leads to the conclusion that the recommended increases in the DEC and DEP reserve margins compared to pre-2016 levels are not supported by the 2016 RA Studies and are not necessary at this time. This evaluation also leads to the conclusion that the 2016 RA Studies have greatly overstated winter resource adequacy risk relative to summer risk, so the winter/summer capacity values of solar resources proposed for use in the 2018 IRPs (Tables 9-B and 9-C, pp. 45-46), as well as the avoided capacity cost weightings (100%/0%, 90%/10%) proposed for use in the Companies' Schedule PP filed in Docket No. E-100, Sub 158, should be rejected, and much more balanced seasonal weights approved.

[35] Response to Data Request SACE/NRDC/Sierra Club 1-21 attachment. These values are based on the forecasts for 2023.

61. The following flaws in the 2016 RA Studies, and associated Solar Capacity Value study, inflate both the winter resource adequacy risk and planning reserve margins, and consequently understate the capacity value of solar resources:

a. The regressions used to estimate the impact of extreme cold on load levels substantially overstate the impact; more accurate regressions more focused on colder temperatures suggest a much more moderate impact of extreme cold on load.

b. The assumption that roughly half as much demand response is available in winter as in summer.

c. The assumption that large amounts of capacity would be held aside for operating reserve and load following, and firm load curtailed, during the rare and very brief load spikes that occur on very cold winter mornings.

62. The flawed economic load forecast uncertainty assumption further inflates the recommended reserve margin:

a. The application of multiple years of economic load forecast uncertainty is inappropriate in a model that does not represent the contingent actions that could be taken if load grows more rapidly than expected.

b. Even accepting the application of multiple years of economic load forecast uncertainty, the probability distribution used, based on CBO data, misrepresents that data, and assigns substantial weight to outcomes that have never occurred in the underlying data.

63. The Companies' approach to estimating seasonal, monthly, and hourly resource adequacy risk, seasonal capacity values of solar resources, and recommended reserve margins, reflected in the 2016 RA Studies and similar Capacity Value Study, will be highly sensitive to various assumptions that can change dramatically in just a few years' time, such as load shapes during summer and winter peak periods, demand response, and penetration of seasonal resources such as wind and solar. This suggests that a fixed rate design, such as reflected in Schedule PP, should not be overly focused on specific months of the year or hours of the day, because the Companies' estimates of the

seasons and hours with resource adequacy risk can change over time as load shapes and the resource mix change. Additionally, the price signals inherent in the rate design can shifts capacity needs to adjacent hours or months. While it is important to strive for accurate price signals, it is also important to strive for price signals that are reasonably stable over time, and likely to remain reasonably accurate as conditions change. Because the Companies' proposed Schedule PP rate designs are based on the same flawed analysis that is highly sensitive to assumptions, I also recommend rejecting the proposed monthly and hourly rate structures.

64. I do not recommend specific seasonal weightings, monthly and hourly rate structures, or reserve margins, as this would require use of the Companies' modeling tools to perform further analysis with the flaws identified above corrected.

65. Finally, this evaluation leads to the following suggestions for future IRPs and supporting resource adequacy studies:

a. The Companies should study the relationship between extreme cold conditions and load, taking into account other relevant factors such as likely facility closures and the impact of wind speeds, to inform future resource adequacy studies.

b. The Companies should further research the drivers of sharp winter load spikes under extreme cold conditions, and develop programs for shaving these rare and brief spikes.

c. The Companies should research the potential for load forecast errors due to economic and demographic forecast errors, and the realistic extent to which this could ultimately lead to less capacity than planned in a delivery year, also to inform future resource adequacy studies. Resource adequacy studies must be internally consistent in their assumptions in this regard – if the potential for adjustments to the resource mix in a one- or two-year ahead time frame are not modeled, only one year of economic load forecast uncertainty should be modeled.

d. The Companies should provide much more scenario analysis and sensitivity analysis of its studies for determining reserve margins and seasonal, monthly, and hourly capacity values. The sensitivity of the recommendations to key assumptions should be explored and documented. For example, as shown above, the 2016 RA Studies results are very sensitive to the choice of 20 or 30 historical weather years, to the details of how extreme cold is assumed to affect load, and to demand response assumptions; such sensitivities should be explored and documented with any such study. The sensitivity of the recommendations to various assumptions that can change over time, including assumptions that could change due to price signals or utility programs, should also be provided.

e. More detailed information about future resource adequacy and related studies should be required. To start, all model reports, and a more comprehensive set of sensitivity analyses, should be provided.

APPENDIX A: LACK OF INFORMATION LIMITING THIS REVIEW

1. Resource adequacy studies necessarily involve numerous assumptions about loads and resources. To fully evaluate such a study requires a careful review of the various assumptions and how they interact through the simulation to create the study results. Of critical importance is the probabilistic representation of loads and resources. Because the approach involves finding the reserve margin to satisfy LOLE = 0.1 (one outage event in ten years), the loss of load will occur only under extremely low-probability combinations of load and resource conditions. Therefore, to validate such a simulation (to gain confidence that the various assumptions are realistic, individually and in combination, and combine to produce realistic results) requires careful review of, among other things, the combinations of multiple rare events that lead to the loss of load. More specifically, it is necessary to examine when the loss of load occurs (what seasons, weather conditions, hour of the day), the load levels when load loss occurs (combining economic and weather uncertainty assumptions), the availability of all generation resources when load loss occurs, the reasons for lack of availability (including purchases, demand response, and energy-limited resources such as pumped hydro).

2. A thorough review should also consider the results of additional sensitivity analyses around various assumptions, to understand the impact of the assumptions on the results and recommendations. Sensitivity analysis will often reveal that the results are unexpectedly sensitive to certain assumptions. This may suggest flaws in the model logic, and/or a need to more carefully consider the particular values chosen for the assumptions.

3. While more details were provided in this proceeding than were available for the Wilson 2017 RM Report, much requested information was refused, including the following:

a. The standard SERVM model reports ("Default Reports", "Debug Reports", "Input Validation Information") for the 17% and 16% winter reserve margin cases.[36]

b. Additional details about the scenarios under which load loss occurs.[37]

c. The load loss details under the base case that supports the recommended 17% winter reserve margin.[38]

d. The load loss details under the alternative case with a 16% winter reserve margin.[39]

e. The load loss details under the four solar penetration cases evaluated in the Solar Capacity Value Study.[40]

f. Hydro and pumped hydro production by hour in the simulations.[41]

g. Additional sensitivity analyses requested pertaining to economic load forecast uncertainty, demand response, and neighbor assistance.[42]

4. Some of these requests were refused, stating that the report was not generated when the model runs were performed, or the information was not saved. However, it is not burdensome to turn on additional reports and re-run a model. The refusal to provide the information reflects an unwillingness to allow the full details of the simulations to come under scrutiny. This lack of information hampered the evaluation of the 2016 RA Studies discussed in this report.

---

[36] Response to Data Request SACE/NRDC/Sierra Club 4-7.

[37] Response to Data Request SACE/NRDC/Sierra Club 4-2.

[38] Response to Data Request SACE/NRDC/Sierra Club 4-4a.

[39] Response to Data Request SACE/NRDC/Sierra Club 4-4b.

[40] Response to Data Request SACE/NRDC/Sierra Club 4-4c.

[41] Response to Data Requests NCSEA 3-49, 3-50, 3-51.

[42] Response to Data Request SACE/NRDC/Sierra Club 4-13.

APPENDIX B: QUALIFICATIONS OF JAMES F. WILSON

James F. Wilson is an economist and independent consultant doing business as Wilson Energy Economics, with a business address of 4800 Hampden Lane Suite 200, Bethesda, Maryland 20814. Mr. Wilson has 35 years of consulting experience, primarily in the electric power and natural gas industries. Many of his consulting assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. His experience and qualifications are further detailed in his CV, available at www.wilsonenec.com.

* pg. 1 of 155 pgs filed in docket system on 11/1/18. Conf version filed same date. KDM

/A vol.2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	)))))	JOINT INITIAL STATEMENT AND PROPOSED STANDARD AVOIDED COST RATE TARIFFS OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

NOW COME Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "the Companies"), pursuant to the North Carolina Utilities Commission's ("Commission" or "NCUC") June 26, 2018 *Order Establishing Biennial Proceeding and Scheduling Hearing* ("2018 Scheduling Order") filed in this docket, and submit the Companies' Joint Initial Statement and Exhibits in support of DEC's and DEP's proposed avoided cost rates, updated Schedule PP tariffs, and standard contract terms and conditions. The Companies' Initial Statement and supporting Exhibits 1-6 present the Companies' updated standard offer avoided cost rates that are being made available to all qualifying cogenerators and small power production facilities ("QFs") that meet the eligibility requirements set forth in DEC's and DEP's respective Schedule PPs and establish a legally enforceable obligation ("LEO") committing to sell the output of their QF generating facility to DEC or DEP on or after the date of this filing. The Companies' Schedule PP avoided cost rates and terms and conditions have been designed to meet the requirements of Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the Federal Energy Regulatory Commission's ("FERC") regulations

& Pg 1 of 317 pgs filed in docket system on 3/27/19. Conf. filed the same date. KAM

/A Vol. 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	)))	REPLY COMMENTS OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Kendrick C. Fentress
Associate General Counsel
Duke Energy Corporation
PO Box 1551 / NCRH 20
Raleigh, North Carolina 27602
Telephone: (919) 546-6733
Kendrick.Fentress@duke-energy.com

E. Brett Breitschwerdt
Kristin M. Athens
McGuireWoods LLP
434 Fayetteville Street, Suite 2600
PO Box 27507 (27611)
Raleigh, North Carolina 27601
(919) 755-6563 [EBB]
(919) 835-5909 [KMA]
bbreitschwerdt@mcguirewoods.com
kathens@mcguirewoods.com

Robert W. Kaylor
Law Office of Robert W. Kaylor, P.A.
353 East Six Forks Road, Suite 260
Raleigh, North Carolina 27609
Telephone: (919) 828-5250
bkaylor@rwkaylorlaw.com

Counsel for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC

1-A
Vol. 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	))))))	STIPULATION OF PARTIAL SETTLEMENT AMONG DUKE ENERGY CAROLINAS, LLC, DUKE ENERGY PROGRESS, LLC, AND THE PUBLIC STAFF

Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP" and together with DEC, "the Companies" or "Duke"), and the North Carolina Utilities Commission—Public Staff ("Public Staff"), hereinafter referred to as the Stipulating Parties, through counsel and pursuant to N.C. Gen. Stat. § 62-69, respectfully submit the following Stipulation of Partial Settlement ("Partial Stipulation") for consideration by the North Carolina Utilities Commission ("Commission") in the above-captioned proceeding. The Stipulating Parties agree and stipulate as follows:

I. <u>BACKGOUND AND SUMMARY OF STIPULATION</u>

A. The Commission's June 26, 2018, *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("Order Establishing Proceeding") directed the Companies to "file proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer periods, with more granularity than the current Option A and Option B rate schedules."

B. On November 1, 2018, the Companies made their Initial Filing ("Joint Initial Statement")[1] in this docket, requesting Commission approval of the Companies' Schedule PP standard avoided cost rates and contract terms and conditions. The Companies' *Joint Initial Statement* explained that the Schedule PP rates were developed using a more granular rate design that better recognizes the value of QF energy and capacity.[2] The Companies' *Joint Initial Statement* also requested the Commission schedule an evidentiary hearing to consider issues related to the new avoided energy and capacity rate design, which were new issues not previously presented to the Commission.[3]

C. The Public Staff's initial comments filed in this docket recommended that additional granularity as part of the avoided energy and capacity rate design would be appropriate and beneficial to ratepayers.[4] The Public Staff proposed an independently-developed "objective" rate design methodology, presented in Public Staff Exhibit 6, as well as an alternative, more granular rate design to "improve price signals to generators and better align rates to those hours when energy and capacity have the highest value to customers."[5] The Public Staff also recommended the Companies rerun their underlying analysis defining the seasonal allocation and capacity payment hours in the Companies' avoided capacity rate designs using the Public Staff's proposed Public Staff Scenario #2 as previously recommended by the Public Staff in Docket No. E-100, Sub 157.

D. On March 27, 2019, the Companies, the Public Staff, and certain other intervenors filed reply comments. The Companies' reply comments explained that

[1] *See* Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Initial Statement and Exhibits, Docket No. E-100, Sub 158 (Nov. 1, 2018) ("Joint Initial Statement").
[2] Joint Initial Statement, at 26-29.
[3] Joint Initial Statement, at 2.
[4] *See* Public Staff Comments on Avoided Cost Filings, Docket No. E-100, Sub 158 at 54 (Feb. 13, 2019) ("Public Staff Initial Comments").
[5] Public Staff Initial Comments, at 55, Exhibit 6.

following submittal of initial comments, the Companies had worked with the Public Staff and, to a lesser extent, other parties to address their concerns surrounding the avoided capacity rate design calculation and also worked with the Public Staff concerning adoption of the philosophies reflected in the Public Staff's proposed energy rate design. The Companies' reply comments proposed an updated avoided energy rate design, following a three-step process similar to the Public Staff's initial proposal, but incorporating a more flexible design that considers the practicality of the design in order to enhance customer acceptance and compliance with the intended price signals.[6] The Public Staff's reply comments expressed support for the Companies' updated energy rate design, but also raised new concerns over the Companies' methodological alignment of energy and capacity months and seasons within their avoided energy and avoided capacity rate designs.[7]

E. Since the filing of reply comments, the Stipulating Parties have had further opportunity to confer regarding reasonable and appropriate standard avoided energy and capacity cost rate designs. As detailed in Part II, the Stipulating Parties have agreed to an updated, more granular avoided energy rate design and updated avoided capacity rate design to be included in the Companies' Schedule PPs, for Commission approval in this proceeding, as well as a proposed methodology, which the Stipulating Parties support as reasonable for reviewing the continued appropriateness of the stipulated rate design in future biennial avoided cost proceedings.

---

[6] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Reply Comments, at 58, 69, Docket No. E-100, Sub 158 (Mar. 27, 2019)("Duke Reply Comments").

[7] Reply Comments of the Public Staff, at 2-3, Docket No. E-100, Sub 158 (Mar. 27, 2019).

II. STIPULATED AVOIDED ENERGY AND AVOIDED CAPACITY RATES.

A. The Stipulating Parties support the avoided energy and avoided capacity months and hours presented in Attachment A as reasonable and appropriate for approval in this proceeding. Additional support is presented in Sections III-IV below.

III. AVOIDED ENERGY RATE DESIGN.

Methodology

A. The Stipulating Parties agree that it is reasonable and appropriate for the Companies' energy rate design to be developed in this biennial proceeding using a modified version of the Public Staff's originally proposed three-step rate design methodology. The stipulated methodology supporting the Stipulated avoided energy and avoided capacity rate design is presented in Attachment B to this Partial Stipulation ("Stipulated Rate Design Methodology").

B. The Stipulating Parties also support the Stipulated Rate Design Methodology as reasonable for reviewing the continued appropriateness of the Companies' avoided energy and avoided capacity rates in future biennial avoided cost proceedings. However, for the avoidance of doubt, the Stipulating Parties may jointly or individually propose modifications to the Stipulated Rate Design Methodology in future biennial avoided cost proceedings.

Seasonal Energy Definitions

C. The stipulated avoided energy rate design's recognition of Summer, Winter and Shoulder seasons is reasonable and appropriate for purposes of this biennial proceeding. Applying the Stipulated Rate Design Methodology for both Companies, the Stipulating Parties agree that the Summer energy season should be defined to include June, July, August, and September; the Winter energy season should be defined to include December, January, and February; and the Shoulder energy season should be defined to include March, April, May, October, and November.

Hourly Energy Allocation

D. The Stipulating Parties agree that the Companies' hourly energy allocations resulting from the above-described Stipulated Rate Design Methodology should employ the concept of higher-priced rating periods, called Premium Peak hours, to be included in the Companies' Winter and Summer seasons for purposes of this biennial proceeding. Specifically, the Stipulating Parties agree that the Premium Peak hours for Winter and Summer are reasonable and appropriate for purposes of this biennial proceeding, as presented in Attachment A to this Partial Stipulation.

IV. AVOIDED CAPACITY RATE DESIGN.

Methodology

A. The Stipulating Parties agree that it is reasonable and appropriate for the Companies' seasonal and hourly allocations of capacity payments to be based upon the loss of load risk identified in the Astrapé Capacity Value of Solar study, as filed in support of the Companies' 2018 Integrated Resource Plans, in Docket No. E-100, Sub 157.

Seasonal Allocation

B. The Stipulating Parties agree that the Companies' proposed seasonal allocation of capacity is reasonable and appropriate for purposes of this biennial proceeding. The avoided capacity rates are calculated to recognize that approximately 90% of

DEC's loss of load risk occurs in the winter, while approximately 100% of DEP's loss of load risk occurs in the winter. For both Companies, the Winter season for capacity payments will include December, January, February, and March for purposes of the rate design in this biennial proceeding. For both Companies, the Summer season for capacity payments will include July and August, although there is no capacity credit payment under the DEP design.

Capacity Hours

C. The Stipulating Parties agree that the Companies' initially proposed Schedule PP capacity pricing periods designating certain PM hours on all days in July and August as the Summer season and certain AM and PM hours on all days in December through March as the Winter season, is reasonable and appropriate for purposes of this biennial proceeding, as presented in Attachment A to this Partial Stipulation.

V. RESOLUTION BASED UPON COMMENTS APPROPRIATE

A. The Stipulating Parties withdraw prior requests presented in the Companies' Joint Initial Statement and the Public Staff's December 31, 2018, Motion for the Commission to receive pre-filed testimony and to hold an evidentiary hearing on rate design issues addressed in this Partial Stipulation.

VI. MISCELLANEOUS PROVISIONS

Effectiveness of Agreement

A. This Stipulation shall be binding upon the Stipulating Parties upon the execution hereof but its substantive terms shall be effective only upon the approval of the Stipulation, in its entirety, by the Commission.

Support of Stipulation

B. The Stipulating Parties will support this Stipulation and take any actions necessary in good faith to support the Stipulation before the Commission.

Execution in Counterparts

C. This Settlement Agreement may be executed by the Stipulating Parties in any number of counterparts, each of which shall be deemed to be an original document, but all of which taken together shall constitute one and the same document and agreement.

Authority

D. The Stipulating Parties and their respective signatories warrant that each has the power and authority to execute this Settlement Agreement, and that the Stipulating Parties have voluntarily executed this Settlement Agreement based on their own independent investigations.

Choice of Law

E. This Stipulation shall be governed by, construed, interpreted, and enforced in accordance with the laws of the State of North Carolina.

Waiver or Modification

F. Neither this Stipulation, nor any provision hereof, may be waived, modified, amended, discharged or terminated except by written instrument signed by the Stipulating Party against whom the enforcement of such waiver, modification, amendment, discharge, or termination is sought, and then only to the extent set forth in such instrument.

Partial Invalidity; Severability

G. If any provision of this Stipulation is held to be illegal, invalid, or unenforceable under any present or future laws, such provision shall be fully severable and the remainder of the Stipulation shall continue in full force. In lieu of any severed provision, there shall be added a provision with such terms and effect, as similar as possible to such illegal, invalid or unenforceable provision as may be possible, legal, valid and enforceable.

This Agreement and Stipulation of Partial Settlement is executed as of the 18th day of April, 2019.

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

By: Kendrick Fentress
Kendrick Fentress
Associate General Counsel
Duke Energy Corporation

PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

By: Lucy E. Edmondson
Lucy Edmondson
Staff Attorney

STIPULATION ATTACHMENT A

Schedule PP Energy and Capaicty Rate Design

Stipulated Seasons	DEC/DEP	DEC/DEP
Month	**Energy**	**Capacity**
January	Winter	Winter
February	Winter	Winter
March	Shoulder	Winter
April	Shoulder	
May	Shoulder	
June	Summer	
July	Summer	Summer
August	Summer	Summer
September	Summer	
October	Shoulder	
November	Shoulder	
December	Winter	Winter

KEY
Summer Premium Peak (PM)
Summer On-Peak (PM)
Summer Off-Peak
Winter Premium Peak (AM)
Winter On-Peak (AM)
Winter On-Peak (PM)
Winter Off Peak
Shoulder On-Peak (AM and PM)
Shoulder Off-Peak

Stipulated Rate Design-Energy

		Hour Ending:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DEC	Summer	Jun - Sep																								
	Winter	Dec - Feb																								
	Shoulder	Remaining																								
		Hour Ending:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DEP	Summer	Jun - Sep																								
	Winter	Dec - Feb																								
	Shoulder	Remaining																								

KEY
Summer (PM)
Winter (AM)
Winter (PM)

Stipulated Rate Design-Capacity

		Hour Ending:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DEC/DEP	Summer	Jul-Aug																								
	Winter	Dec-Mar																								
	Shoulder																									

General Guidelines for Determining Seasons and Energy Pricing Periods in Avoided Cost Rates

The following guidelines and considerations should be used to evaluate energy hours and seasons that are appropriate for fixing Duke Energy's avoided cost rates. Based upon the variability in customer usage, establishment of an appropriate rate design must evaluate many factors, making a fixed mathematical approach problematic. The design must consider such things as: (1) historic, forecasted or combination of system load, (2) historic and forecasted marginal energy cost, (3) loss of load expectation and hourly reserve margin, (4) technological changes in customer usage, such as the impact of electric vehicles, or the addition of customer-owned distributed generation or batteries. Because purchase rates are often set for a long period of time, it is important to not be overly specific because a brief pricing period may no longer reflect actual higher system cost in the later years of the contract. The rate periods must not, however, be set on too broad a period because it will reduce price differentials and yield less incentive for generators to produce power during times that are of the most value to the utility and its customers. The basic process should consider: (1) Establishing seasons based upon a review of hourly system load data during each month of the year – it is often helpful if the energy and capacity months are aligned to optimize the design's price signals and minimize customer confusion; (2) Determine loads and marginal costs to be used for On-Peak, Off-Peak, and Premium Peak classification; and (3) Using the load and marginal cost data to classify hours by season (i.e., On-Peak, Off-Peak, and Premium Peak hours).

STEPS

1) <u>Establish seasons using hourly load data analysis.</u>
   i) Determine Load data period:
      (1) The preferred approach is to use projected hourly load, with an offset for renewable supply, for the future period defined by the longest contract term offered under the standard rate offer. Use of projected data is most appropriate because it best reflects the Company's expectation of future cost impacts.
      (2) As an alternative, if historic data are believed to be reasonably representative of the future period, a combination of historical and projected hourly load data may be appropriate. Ideally, the recommended seasons will align with both historic and projected load information.
   ii) Determine the seasons for each utility

(1) Once load data is determined, calculate the average load for the period by month, and compare to the average annual load for the period.

(a) If the monthly average load is greater than the annual average load, the month is classified as either Summer or Winter peak season.

(b) If the monthly average load is not greater than the annual average load, the month is classified as shoulder season.

(2) This method of determination is a general guideline, and should be administered with consideration of other factors that may be relevant to the decision. For example, comparison to other analysis types for reasonableness such as loss of load hours or load shape may identify adjustments for consideration. The addition of multiple seasons adds complexity to the design and negatively impacts customer understanding and billing. Multiple seasons however offer stronger price signals that are more reflective of the Company's avoided cost. Care should be used to optimize the design to address these considerations.

2) Determine marginal cost by Rating Period (On-Peak, Off-Peak, and Premium Peak classification).

i) Analyze Marginal cost data

(1) Use a data set comprised of historical marginal costs, projected marginal costs, or combination of the two for the hour-selection analysis.

(2) The selected hourly marginal cost data are used to create hourly average cost by month to identify hours within each season into On-Peak, Off-Peak, and Premium Peak periods.

3) Step 3: Classify hours into Rating Periods (i.e., On-Peak, Off-Peak, and Premium Peak hours)

i) Identify Off-Peak hours

(1) Once marginal cost data is determined, calculate the average marginal cost for each hour in each month by season, and compare to the average marginal cost for that season.

(a) If the hour's average marginal cost is less than the season average marginal cost, the hour is classified as Off-Peak.

(b) If the hour's average marginal cost is not less than the season average marginal cost, the hour is classified as either On-Peak or Premium Peak.

(2) Identify On-Peak and Premium Peak hours

(a) Beginning with all hours not classified as Off-Peak, Premium Peak hours would be hours with an average marginal cost in a selected upper percentile when measured against all average hourly marginal costs in that season.

(b) The selected upper percentile should identify a number of peak hours which are sufficient to create a balance that is not overly specific on when the highest values will occur, but is not overly broad to avoid the reduction in price differentials.

(c) Consideration of the following guidelines for reasonableness for the resulting number of Premium Peak hours and the hours selected:

  (i) Minimizing customer confusion

  (ii) Reflecting no premium peak hours in the shoulder season.

  (iii) Reflecting a minimum of three or greater adjacent premium peak hours in the Summer and Winter peak seasons.

(d) Important considerations:

  (i) The number of Premium Peak hours should consider:

    a. Potential price signal impacts

    b. Uncertainty of future timing of high value hours

    c. Other relevant factors

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *Stipulation of Partial Settlement Among Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and the Public Staff*, filed in Docket No. E-100, Sub 158, was served electronically or via U.S. mail, first-class postage prepaid, upon all parties of record.

This, the 18th day of April, 2018.

/s/E. Brett Breitschwerdt

E. Brett Breitschwerdt
McGuireWoods LLP
434 Fayetteville Street, Suite 2600
PO Box 27507 (27611)
Raleigh, North Carolina 27601
Telephone: (919) 755-6563
bbreitschwerdt@mcguirewoods.com

Attorney for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC

1A
vol. 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	)))))	STIPULATION OF PARTIAL SETTLEMENT REGARDING SOLAR INTEGRATION SERVICES CHARGE

Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP" and together with DEC, "the Companies" or "Duke"), and the North Carolina Utilities Commission—Public Staff ("Public Staff"), hereinafter referred to as the Stipulating Parties, through counsel and pursuant to N.C. Gen. Stat. § 62-69, respectfully submit the following Stipulation of Partial Settlement ("Partial Stipulation") regarding Duke's proposed solar Integration Services Charge ("Integration Services Charge" or "SISC") for consideration by the North Carolina Utilities Commission ("Commission") in the above-captioned proceeding. The Stipulating Parties agree and stipulate as follows:

I. BACKGROUND AND SUMMARY OF STIPULATION

A. In 2017, the North Carolina General Assembly passed Session Law 2017-192 ("HB 589"), which, in part, amended N.C. Gen. Stat. § 62-156(b) and (c) to establish that the characteristics of the power supplied by a Qualifying Facility ("QF") should be taken into account in designing the rates offered to smaller QFs under the Companies' Schedule PP avoided cost tariffs.[1] The Commission similarly recognized in the 2016

[1] The Companies' "standard offer" tariffs available to smaller QFs under N.C. Gen. Stat. § 62-156(b) is limited to small power producers with a design capacity up to and including 1,000 kilowatts.

biennial avoided cost proceeding that Duke may "propose schedules specific to QFs that provide intermittent, non-dispatchable power, if the Utilities' cost data 'demonstrates marked differences' in the value of the energy and capacity provided by these QFs."[2]

B. The Commission's June 26, 2018, *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing* ("Order Establishing Proceeding") directed the Companies to "consider [] factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable."[3]

C. On November 1, 2018, the Companies filed their Joint Initial Statement[4] in this docket, requesting Commission approval of DEC's and DEP's Schedule PP standard avoided cost rates and contract terms and conditions, as well as implementation of a new Integration Services Charge applicable to intermittent solar QFs. The Integration Services Charge is designed to recognize the impact on the Companies' operating reserves, or generation ancillary service requirements, of integrating existing and new variable and non-dispatchable solar capacity and to assign such costs to solar QFs whose integration is causing the increased operating costs.[5] The Integration Services Charge is supported by the Solar Ancillary Services Study developed by Astrapé Consulting ("Astrapé"), which analyzed the incremental ancillary services costs to operate the DEC and DEP fleets to reliably integrate increasing penetrations of intermittent solar generation. The Integration Services Charge represents Duke's quantification of DEC's and DEP's respective average ancillary services costs to integrate the existing plus Transition MW of solar prescribed

---

[2] *See Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* at 97, Docket No. E-100, Sub 148 (Oct. 11, 2017) ("*2016 Sub 148 Order*").
[3] *Order Establishing Biennial Proceeding, Requiring Data, and Scheduling Public Hearing,* at 1, Docket No. E-100, Sub 158 (June 26, 2018).
[4] *See* Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Initial Statement and Exhibits, Docket No. E-100, Sub 158 (filed Nov. 1, 2018) ("Joint Initial Statement").
[5] Joint Initial Statement, at 30-34.

under HB 589.[6] The Astrape Study supports the Companies' proposed Integration Services Charges of $1.10/MWh for DEC and $2.39/MWh for DEP.[7]

D. On December 14, 2018, the Public Staff met with Duke and Astrapé to discuss the Astrapé Study and the underlying data assumptions and methodology used to quantify the Companies' increased ancillary services requirements and to calculate the proposed Integration Services Charge.

E. On February 12, 2019, the Public Staff's initial comments stated that they had "reviewed the Astrapé Study and generally agree[d] that DEC and DEP face operational challenges resulting from the current and pending amount of a single specific aggregate resource connected to its electrical grid" and "agree[d] that intermittent and non-dispatchable resources have a direct impact on system operations, including costs."[8] The Public Staff went on to state that they "agree[d] with the Astrapé Study's basic premise" that the Companies' fleet resources must have sufficient flexibility to ramp up and down to accommodate fluctuations in solar output.[9] The Public Staff's Comments also initially identified a number of concerns with the Astrapé Study's modeling and data assumptions used to develop the Integration Services Charge:

1. The proposed SISC would refresh every two years, regardless of the contract term.
2. The Astrapé Study models DEC and DEP as load islands.
3. When setting a benchmark for system reliability, Duke uses a "no solar" scenario.
4. Solar volatility was modeled using only one year of historical data.

[6] The "Transition MW" concept refers to the approximately 3,500 MW of legacy QF solar identified in the CPRE statute, N.C. Gen. Stat. § 62-110.8(b)(1).
[7] Joint Initial Statement, at 33.
[8] *See* Public Staff Comments on Avoided Cost Filings, at 34-35, Docket No. E-100, Sub 158 (Feb. 13, 2019) ("Public Staff Initial Comments").
[9] *Id.* at 35.

5. The Astrapé Study only reflects an increase in one type of ancillary service to address solar intermittency, and this particular category of ancillary service is exogenous to the model (forced).[10]

F. On March 27, 2019, the Companies, the Public Staff, and certain other interveners filed reply comments. The Companies' reply comments extensively addressed each of the Public Staff's five concerns as well as refuted interveners' criticisms of the Astrapé Study and the appropriateness of the Integration Services Charge. Duke's reply comments explained that the Public Staff's concerns with the Astrapé Study were not warranted, and provided additional detailed support for the Astrapé Study's data, methodology, results, and conclusions.[11] The Public Staff's reply comments reiterated concerns number 1, 3, and 4 detailed above, but withdrew concerns 2 and 5, explaining that Duke had provided the Public Staff information prior to filing reply comments that resolved the Public Staff's concerns.[12]

G. Since the filing of reply comments, the Stipulating Parties have had further opportunity to confer regarding the Astrapé Study and the Companies' Integration Services Charge and have now agreed to the methodology, quantification, and applicability of the SISC for purposes of this proceeding, as follows:

II. INTEGRATION SERVICES CHARGE SHALL APPLY PROSPECTIVELY

A. The Integration Services Charge shall be applied prospectively to all QF solar generators committing to sell under the Companies' E-100, Sub 158 standard offer avoided cost tariffs. In addition, the Integration Services Charge shall be applied

[10] Reply Comments of the Public Staff, at 16-17, Docket No. E-100, Sub 158 (Mar. 27, 2019) ("Public Staff Reply Comments").
[11] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Reply Comments, at 58, 69, Docket No. E-100, Sub 158 (Mar. 27, 2019)("Duke Reply Comments").
[12] Public Staff Reply Comments, at 16-18.

to all other solar generators that either have committed to sell or prospectively commit to sell to Duke at future Schedule PP or negotiated avoided cost rates on or after November 1, 2018, unless those solar generators can demonstrate that the facility is capable of operating, and shall contractually agree to operate, in a manner that materially reduces or eliminates the need for additional ancillary service requirements (as reasonably determined by the Companies), through inclusion of energy storage devices, dispatchable contracts, or other mechanisms that materially reduce or eliminate the intermittency of the output from the solar generators ("controlled solar generators"). A solar generator seeking to reduce or eliminate the applicability of the Integration Services Charge shall contractually agree to construct and operate its solar generating facility and co-located energy storage to meet design specifications and operational requirements, as reasonably determined by Duke to be required to reduce or eliminate the need for additional ancillary services, including, but not limited to, the relative capacity of the energy storage facility, operational control and performance requirements, as well as associated monitoring of the facility's operations and remedies for failure to comply.

<u>Exemption for Solar Generators Committing to Sell prior to November 1, 2018</u>

B. Solar generators that have contracted to sell to the Companies under prior vintages of the Schedule PP standard offer or negotiated avoided cost rates or having otherwise committed to sell to the Companies prior to November 1, 2018, shall be exempt from the Integration Services Charge for the duration of their current power purchase agreement ("PPA"). For the avoidance of doubt, the Parties agree that solar PPA proposals selected in the initial Competitive Procurement of Renewable

Energy ("CRPE") Program request for proposals solicitation ("Tranche 1 RFP"), are intended to be exempted from the Integration Services Charge for the initial 20-year term, as the Tranche 1 RFP guidelines and requirements were issued by the CPRE independent administrator, Accion, Inc., on July 10, 2018, preceding the Companies' filing of the proposed SISC in this docket, and did not include any reference to the SISC. The Stipulating Parties agree that it is appropriate to consider the ancillary services costs of adding incremental solar, and the potential applicability of the Integration Services Charge to solar generation solicited in CPRE Tranche 2 and other future CPRE Tranches.

C. Upon expiration of any existing solar QF PPA, including solar QFs exempted from the Integration Services Charge in II.B above, the then-applicable SISC shall be applied upon the solar QF committing to sell to Duke under a new PPA in the future.

III. QUANTIFICATION OF SOLAR-RELATED ANCILLARY SERVICES COSTS

A. The Stipulating Parties agree that the Astrapé Study's data, methodology, results, and conclusions are reasonable for purposes of quantifying the Companies' "average" and "incremental" ancillary services costs attributable to integrating solar generation, as well as for purposes of calculating the Companies' Integration Services Charge.

IV. SOLAR INTEGRATION SERVICES CHARGE

A. The Stipulating Parties agree that the Companies' Integration Services Charge should be calculated based upon DEC's and DEP's "average" ancillary services costs associated with integrating all uncontrolled solar generation versus assigning higher "incremental" ancillary services costs to future solar generators because both currently installed and future solar generators, if uncontrolled, have a similar impact and contribution to the Companies' increased ancillary service requirements.

B. For purpose of quantifying the average ancillary services impacts of integrating current and projected levels of solar penetration and fixing a reasonable and appropriate Integration Services Charge, the Existing Plus Transition levels (840 MW in DEC and 2,950 MW in DEP) of solar generation quantified in the Astrape Study are reasonable and appropriate for use in this proceeding.

C. The Stipulating Parties agree that the Astrapé Study's quantification of the Companies' average Existing Plus Transition level of ancillary services costs, in the amounts of $1.10/MWh for DEC and $2.39/MWh for DEP, are reasonable and appropriate for purposes of fixing Integration Services Charges in this proceeding. To the extent the Commission's final order in the Sub 158 Docket modifies the methodology or inputs used to quantify the Integration Services Charge, the Stipulating Parties agree to recalculate the Integration Services Charge consistent with the Commission's modifications.

D. For the avoidance of doubt, the Stipulating Parties agree that any Solar Integration Services Charge collected from solar generators will be credited to ratepayers in future fuel proceedings to offset the increased fuel and fuel-related costs associated with integrating solar resources.

V. <u>BIENNIAL REVIEW OF SOLAR INTEGRATION COSTS AND CHARGES</u>

A. The Stipulating Parties agree that it is reasonable and appropriate for Duke to biennially review and update the Companies' average and incremental ancillary services costs. The Integration Services Charge should be adjusted in future biennial avoided cost proceedings to accurately reflect changes to DEC's and DEP's average ancillary services costs as incremental solar is installed on the DEC and DEP systems.

B. The Integration Services Charges approved in this proceeding should continue in effect until the date that the Companies' file updated solar ancillary services studies and/or analyses in the next biennial avoided cost proceeding that quantify DEC's and DEP's average and incremental costs of solar integration. The new Integration Services Charge would then become effective subject to true-up, if required, after a final Commission Order on the Companies' biennial avoided costs filing, similar to the availability of Companies' standard offer and variable rates.

VI. CAP ON FUTURE INCREASES TO INTEGRATION SERVICES CHARGES

A. The Stipulating Parties agree to cap potential future increases in the Integration Services Charges for all uncontrolled solar generators committing to sell to DEC and DEP prior to the next biennial avoided cost proceeding when the Companies' ancillary services costs will next be reviewed and updated (the "Sub 158 Vintage"). The Stipulating Parties agree that capping future adjustments to the Companies' Integration Services Charge is reasonable and appropriate to mitigate the risk for Sub 158 Vintage solar generators of currently-unquantifiable potential future increases in DEC's and DEP's average ancillary services costs attributable to the installation of incremental solar on the Companies' systems during the term of Sub 158 Vintage PPAs.

Methodology

B. The Cap shall be based upon the Companies' incremental ancillary services costs for the last 100 MW of solar generation forecasted to be installed within the biennial vintage period. Specific to the current 158 Vintage, the Stipulating Parties agree that the cap should be developed based upon the Companies' 2018 Integrated Resource Plans' ("IRP") projections of installed solar at the end of the current Sub 158 biennial period (2020). DEC's 2018 IRP forecasts 1,588 MW of installed solar generation in 2020, while DEP's 2018 IRP forecasts 3,061 MW of installed solar generation in 2020.

C. The same modeling methodology used to develop the average Integration Services Charge, as described in Section II above, should be used to quantify the incremental ancillary services requirements used for purposes of establishing the cap.

D. Applying the above-described methodology, the Stipulating Parties agree that that following incremental caps on the Integration Services Charge are reasonable and appropriate for Sub 158 Vintage solar generators: DEC: \$3.22/MWh. DEP \$6.70/MWh. To the extent the Commission's final order in the Sub 158 Docket modifies the methodology or inputs used to quantify the Integration Services Charge Cap, the Stipulating Parties agree to recalculate the Integration Services Charge Cap consistent with the Commission's modifications.

E. For the avoidance of doubt, the Stipulating Parties agree that if Duke's actual average ancillary services costs exceed the incremental cap for a given biennial vintage of solar generators, then the Companies shall charge all uncontrolled solar generators of that vintage the lesser of the most current Integration Services Charge approved during the most current biennial period or the pre-established incremental capped level of SISC applicable to that vintage. A new average SISC and incremental cap shall become applicable at the time the solar generator commits to enter into a new PPA to sell its output to DEC or DEP.

Future Biennial Avoided Cost Proceedings

F. The Stipulating Parties support applying this methodology to establish a similar incremental ancillary services cost cap on future solar integration services charges for future biennial avoided costs Vintages.

Other Agreements Relating to Cap

G. The Stipulating Parties further agree that the Cap recommended by the Public Staff and agreed to by the Companies herein is not intended to and shall in no way limit the Companies' rights and ability to recover their purchased power costs from solar generators under N.C. Gen. Stat. §§ 62-133.2(a1)(4), (5), and (10), as well as any other applicable statutes and Commission rules.

VII. MISCELLANEOUS PROVISIONS

Effectiveness of Agreement

A. This Stipulation shall be binding upon the Stipulating Parties upon the execution hereof but its substantive terms shall be effective only upon the approval of the Stipulation, in its entirety, by the Commission.

Support of Stipulation

B. The Stipulating Parties will support this Stipulation and take any actions necessary in good faith to support the Stipulation before the Commission.

Execution in Counterparts

C. This Settlement Agreement may be executed by the Stipulating Parties in any number of counterparts, each of which shall be deemed to be an original document, but all of which taken together shall constitute one and the same document and agreement.

Authority

D. The Stipulating Parties and their respective signatories warrant that each has the power and authority to execute this Settlement Agreement, and that the Stipulating Parties have voluntarily executed this Settlement Agreement based on their own independent investigations.

Choice of Law

E. This Stipulation shall be governed by, construed, interpreted, and enforced in accordance with the laws of the State of North Carolina.

Waiver or Modification

F. Neither this Stipulation, nor any provision hereof, may be waived, modified, amended, discharged or terminated except by written instrument signed by the Stipulating Party against whom the enforcement of such waiver, modification, amendment, discharge, or termination is sought, and then only to the extent set forth in such instrument.

Partial Invalidity; Severability

G. If any provision of this Stipulation is held to be illegal, invalid, or unenforceable under any present or future laws, such provision shall be fully severable and the remainder of the Stipulation shall continue in full force. In lieu of any severed provision, there shall be added a provision with such terms and effect, as similar as possible to such illegal, invalid or unenforceable provision as may be possible, legal, valid and enforceable.

This Agreement and Stipulation of Partial Settlement is executed as of the 21st day of May, 2019.

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

By: Kendrick C. Fentress
Kendrick Fentress
Associate General Counsel
Duke Energy Corporation

PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

By: Tim
Tim Dodge
Staff Attorney

CERTIFICATE OF SERVICE

I certify that a copy of Stipulation of Partial Settlement Regarding Solar Integration Services Charge between and among Duke Energy Carolinas, LLC; Duke Energy Progress, LLC and the Public Staff of the North Carolina Utilities Commission in Docket No. 100, Sub 158, has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 21st day of May, 2019.

By: Kendrick C. Fentress

Kendrick C. Fentress
Associate General Counsel
Duke Energy Corporation
P.O. Box 1551/NCRH 20
Raleigh, North Carolina 27602
Tel: 919.546.6733
Kendrick.Fentress@duke-energy.com