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September 4, 2020

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Duke Energy Progress, LLC's DSM/EE Cost Recovery Rider – Rebuttal Testimony
Docket No. E-2, Sub 1252

Dear Ms. Campbell:

Enclosed for filing is Duke Energy Progress, LLC's Rebuttal Testimony of Robert P. Evans and Timothy J. Duff for filing in connection with the referenced matter.

If you have any questions, please let me know.

Sincerely,

Robert W. Kaylor

Robert W. Kaylor

Enclosures

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Progress, LLC's Rebuttal Testimony of Robert P. Evans and Timothy J. Duff, in Docket No. E-2, Sub 1252, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to parties of record:

This the 4th day of September, 2020.

Robert W. Kaylor

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ATTORNEY FOR DUKE ENERGY
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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1252

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**REBUTTAL TESTIMONY OF**
for Approval of Demand-Side Management	)	**ROBERT P. EVANS FOR**
and Energy Efficiency Cost Recovery Rider	)	**DUKE ENERGY PROGRESS,**
Pursuant to N.C. Gen. Stat. § 62-133.9 and	)	**LLC**
Commission Rule R8-69	)	

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION WITH DUKE ENERGY.

A. My name is Robert P. Evans, and my business address is 410 S. Wilmington Street, Raleigh, North Carolina. I am employed by Duke Energy Corporation as Senior Manager-Strategy and Collaboration for the Carolinas in the Portfolio Analysis and Regulatory Strategy group.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN SUPPORT OF DUKE ENERGY PROGRESS, LLC'S ("COMPANY") APPLICATION IN THIS DOCKET?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to portions of the testimony of David Williamson filed on behalf of the Public Staff and Forest Bradley-Wright filed on behalf of the North Carolina Justice Center ("NCJC"), the North Carolina Housing Coalition, and the Southern Alliance for Clean Energy ("SACE").

Q. WILL YOU DESCRIBE THE PORTIONS OF WITNESS DAVID WILLIAMSON'S TESTIMONY TO WHICH YOU ARE RESPONDING?

A. Yes. There are several portions of witness Williamson's testimony that cause concerns; specifically, those portions related to his recommendations regarding lighting transformation in North Carolina, the My Home Energy Report ("MyHER") Program, the Neighborhood Energy Saver ("NES") Program's

Evaluation, Measurement and Verification ("EM&V") report and his recommendations concerning the Company's Grid Improvement Plan ("GIP").

Q. WHAT ARE YOUR CONCERNS RELATING TO WITNESS WILLIAMSON'S RECOMMENDATION REGARDING LIGHTING TRANSFORMATION IN NORTH CAROLINA?

A. Starting on line 8 on page 19 of his testimony, witness Williamson recommends the following:

> *Based on the Public Staff's review of lighting-related EM&V reports over the last three years, and the Company's acknowledgement of upcoming lighting standard changes as they alter their program offerings, I recommend that the Commission require that, beginning in 2021, only specialty LED lighting be considered for recognition as energy efficiency.*

Although the Company agrees in part with witness Williamson that significant market transformation with respect to LED non-specialty lighting has taken place, this transformation has not been universal, particularly with respect to low-income and multifamily residences. The Company still sees an ongoing need for non-specialty energy efficient A-line bulbs in both low-income and multifamily residences to enable those customers to participate in the benefits of energy efficient lighting. For this reason, the Company intends to continue providing A-line bulbs to low-income customers through its direct install Neighborhood Energy Saver Program and provide them through outlets such as Goodwill, Dollar General, Dollar Tree and Habitat stores. In addition, the Company intends to continue replacing inefficient lighting through its

Multifamily direct install program. Future needs in low-income and multifamily residences will be closely monitored as independent EM&V studies for these programs determine their saturation with standard high efficiency lighting.

Q. DO YOU AGREE WITH WITNESS WILLIAMSON'S STATEMENTS AND RECOMMENDATIONS RELATED TO THE COMPANY'S MYHER PROGRAM?

A. No, I do not. Witness Williamson indicates that the Public Staff was skeptical that the cost and utility incentives associated with the MyHER Program are justified. He believes that it would be appropriate for the Commission to require the Company to assess the cost and benefits of continuing to offer the MyHER Program versus providing the same comparison through adding tips to other channels such as Duke Energy Mobile App and Download My Data.

Public Staff witness Williamson attempts to prove that the deployment of AMI metering will negate the value of the MyHER program because customers will be able to see their usage in near real-time, and he presents evidence that DEP customers have begun accessing their own data using the "Download My Data" functionality.

Witness Williamson further contends that the Public Staff believes *that the MyHER program will simply be a duplicate provision of the same data to the customer…*" (Page 24 Line 10) and further states that the only incremental difference between customers obtaining their own data and the information provided in the MyHER report would be the EE tips that are provided as part of the MyHER report.

Witness Williamson's testimony, however, ignores the real value of the MyHER report, which is the provision of the normative comparison of a customer's usage versus the usage of a similar group of customers, as well as a comparison of their usage to a model Efficient Home. Witness Williamson acknowledges as much when he testifies that *"The success of the MyHER program relies on the Company's collection of individual customers' data, and then analyzing this data in relation to similar nearby customers"*. (Page 22, Line 20)

In his own testimony, witness Williamson points out that the real value of the MyHER program is the normative comparison portion of the analysis, but he attempts to show that customers could obtain that same valuable information by simply looking at their own usage in a vacuum. It seems inconsistent for witness Williamson on the one hand to say that the value of the MyHER report is the normative comparison but yet in the same argument to state that *"The only incremental difference would be the EE tips that would be offered through the MyHER report"* (Page 24, Line 11), a statement that conflicts with his earlier statement that the ability to view their own usage in comparison to their peers as well as to a modeled Efficient Home is a value to customers. When approving the MyHER program for DEC, the Commission itself recognized that MyHER "has the potential to encourage EE by providing participants with periodic personalized reports *containing comparative usage data* for similar residences in the same geographic area and personalized recommendations for more efficient use of energy in their homes, which should motivate participants to better manage and reduce their energy consumption."[1]

Witness Williamson suggests that the Commission should require the Company to assess the costs and benefits of the MyHER program, which he describes as "a comparison of energy consumption and EE tips" (Page 25, Line 2), versus providing the same comparison and tips through another channel; however, the "other channels" that witness Williamson identifies in his testimony do not contain the key element that he admits is the most valuable aspect of the MyHER program, the normative comparison of a customer's usage to other similar customers.

While it might be useful for a Customer to be able to access their own AMI data to monitor their own usage information, without having a way to compare their usage to their peers and a modeled Efficient Home, customers would have no way to understand their own usage in the context of how they compare to similar customers.

Q. WHAT CONCERNS DO YOU HAVE RELATING TO WITNESS WILLIAMSON'S NES EM&V RECOMMENDATIONS?

A. There are several portions of witness Williamson's testimony concerning the Neighborhood Energy Saver Program to which I am responding, namely that 1) the Company utilize a billing analysis in the next NES evaluation to determine Program savings; 2) in the absence of a billing analysis that future Program evaluations using engineering estimates incorporate a net to gross ratio

[1] Order Approving Program, Docket No. E-7, Sub 1015, issued Sept. 11, 2012 at p. 6. (Emphasis added.)

("NTGR") determination and that the baseline wattage assumptions should be reviewed; and 3) the next evaluation should be completed "as soon as possible" with a completion date targeted for 2021.

Q. DO YOU AGREE WITH WITNESS WILLIAMSON'S STATEMENT THAT A BILLING ANALYSIS IS A PREFERABLE EVALUATION METHOD TO DETERMINE PROGRAM SAVINGS FOR THE NES PROGRAM?

A. Yes, the Company agrees with witness Williamson's assessment that a billing analysis is a preferable evaluation methodology for this program because it provides a more accurate representation of actual program performance. A billing analysis would be able to determine the program savings from the measures installed at the home, plus savings from behavioral actions that program participants take as a direct result of the in-person education that is a key component of the program. In addition, the methodology inherently assesses associated spillover.

Q. WITNESS WILLIAMSON RECOMMENDS THAT THE NEXT NES EVALUATION RELY ON A BILLING ANALYSIS TO DETERMINE PROGRAM SAVINGS. DOES THE COMPANY AGREE WITH THAT RECOMMENDATION?

A. Although the Company agrees with witness Williamson's recommendation, the Company asks for flexibility, should the results of the billing analysis determine that methodology is not an appropriate one. The independent evaluator anticipates utilizing a billing analysis for the next NES evaluation; however, there are caveats to this methodology. Should the billing analyses determine that there are inherent consumption differences that cannot be controlled between the treatment group, that is, the group of participants being evaluated, versus that of the control group, it is better to utilize an engineering analysis because it is an acceptable analytical approach as witness Williamson indicates on page 43 of his testimony.

Q. HOW DOES THE COMPANY RESPOND TO WITNESS WILLIAMSON'S RECOMMENDATION THAT AN ENGINEERING ANALYSIS INCORPORATE A NET TO GROSS RATIO AND A REVIEW OF BASELINE WATTAGE ASSUMPTIONS?

A. While the deemed NTGR of 1.0 is standard practice for income-qualified programs, the independent evaluator will examine whether a NTGR is applicable for this program, and, more specifically, this jurisdiction. If feasible, the evaluator will investigate framing free ridership questions as they relate to the broader lighting market. Also, the evaluator will review whether a baseline wattage assumption is appropriate given the region, target population, and types of lamps included in the program.

Q. WITNESS WILLIAMSON RECOMMENDS THAT THE COMPANY CONDUCT THE NEXT NES EVALUATION AS SOON AS POSSIBLE, WITH A TARGET COMPLETION DATE ON OR BEFORE THE YEAR 2021. DOES THE COMPANY AGREE WITH THAT TIMEFRAME?

A. The Company does not agree with that timeframe. Due to COVID-19, the program suspended in-home NES operations in March 2020 and has not yet resumed normal operations. Not only will this suspension reduce the number of participants available as a comparison control group, it will create delays as the evaluator tries to evaluate consumption data that will show anomalous consumption patterns due to the COVID stay-at-home restrictions. The Company will endeavor to work through the evaluation activities as quickly as possible post-suspension; however, a 2021 timeframe may be impossible to achieve.

Q. DO YOU AGREE WITH WITNESS WILLIAMSON'S RECOMMENDATIONS THAT THE COMPANY ANALYZE HOW GIP WILL AFFECT THE PERFORMANCE OF DSM/EE PROGRAMS?

A. No, I do not. In response to the Public Staff and other intervenors' data requests, the Company has provided voluminous amounts of data, analyses, and general information regarding the Company's GIP program, including its Integrated Volt/Var Controls ("IVVC") program, as part of Docket No. E-7, Sub 1214 and Duke Energy Progress, LLC's Docket No. E-2, Sub 1219, which are both pending general rate cases. Specifically, information has been shared regarding the Company's DSDR to CVR Conversion program. The Company is certainly not opposed to reporting information about the DSDR to CVR project and has agreed to work with the Public Staff on reporting for GIP programs as outlined in the Company's Second Agreement and Partial Settlement with the Public Staff in the pending Duke Energy Progress rate case. The additional analysis recommended by witness Williamson is not necessary and would be duplicative. Any influence or interaction between GIP and DSM/EE programs will be evaluated and captured in the existing reporting protocols.

Q. HOW DOES THE COMPANY RESPOND TO WITNESS WILLIAMSON'S RECOMMENDATIONS THAT THE NEXT DSM/EE

RIDER FILING INCLUDE REPORTING ON GIP IMPLEMENTATION AND ITS IMPACTS ON THE COMPANY'S DSM/EE PORTFOLIO?

A. I do not agree with witness Williamson's recommendation. As previously mentioned, recommendations on reporting on the GIP status are addressed extensively in testimony filed in the pending rate cases, including in the direct and rebuttal testimony of witness Jay W. Oliver, and in the Second Agreement and Partial Settlement with the Public Staff in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214. Accordingly, integrating additional GIP status reporting in the separate DSM/EE proceedings is unnecessary and will likely lead to confusion because the programs are separate initiatives designed to accomplish clearly defined, distinguishable goals. Because the Company (or any other party for that matter) has not recommended to have any of the programs in the GIP be filed or considered as part of the DSM/EE rider recovery proceeding, the DSM/EE rider recovery docket is not the appropriate forum for the types of information witness Williamson is recommending for reporting. Once again, any influence or interaction between GIP and DSM/EE program will be evaluated and captured in the existing reporting protocols.

Q. HOW DOES THE COMPANY RESPOND TO WITNESS WILLIAMSON'S RECOMMENDATIONS THAT THE COMPANY EXPLAIN IN THE NEXT DSM/EE RIDER FILING HOW IT WILL DISTINGUISH PEAK DEMAND AND ENERGY SAVINGS RESULTING FROM THE GIP FROM THOSE RESULTING FROM THE DSM/EE PORTFOLIO?

A. The Company's request for deferral accounting for the GIP programs agreed to in the Second Agreement and Stipulation of Partial Settlement in the general rate cases noted above are currently pending before this Commission. Although the Company acknowledges that changing the predominant operational strategy in DEP from DSDR to CVR would affect the amount of maximum peak shaving capability, time is needed to allow the Company to complete testing and analysis. To determine the reduction in peak shaving capability, the Company will need to implement CVR capabilities in the DEP Distribution Management System and then perform testing to determine the amount of maximum peak shaving capability with the CVR enhancements. Because this CVR testing has not been implemented yet, determining treatment of DSDR in this proceeding is premature, and discussions on the treatment of DSDR in subsequent DSM/EE proceedings are more appropriate.

Q. WHAT IS YOUR RESPONSE TO WITNESS BRADLEY-WRIGHT'S CONCERN REGARDING DEP'S PROJECTION OF SAVINGS BELOW 1% OF PRIOR RETAIL SALES?

A. Although the aspirational goal to reduce energy consumption by 1% of prior year retail sales is a benchmarks by which utilities judge their performance, it is not the only way to measure a portfolio's effectiveness. Other metrics used to evaluate portfolio performance capture demand reductions, consider the ratio of costs to benefits, or differentiate between savings across customer segments. The Company remains committed to achieving all cost-effective energy savings up to and exceeding 1% when possible, but it is also focusing on maximizing the performance of individual programs year over year, improving the offerings within the portfolio as a whole, including demand response programs, and striving to achieve the most benefits for customers at the least cost.

Q. DO YOU BELIEVE THAT THE COLLABORATIVE MUST PREPARE WRITTEN REPORTS AND DEVELOP PROJECT SCHEDULES AND TIMELINES TO BE EFFECTIVE AS AN ADVISORY FORUM?

A. No, Duke relies on the Collaborative's expertise and solicits input from them during meetings and conference calls. Of course, any reports a member prepares or submits to the Company for discussion in a Collaborative meeting is a welcome contribution. However, out of respect for the members' time and their professional duties, and to encourage participation from a wide range of technical backgrounds, the Company is judicious with ad hoc requests and avoids asking the Collaborative to perform unnecessarily burdensome tasks.

Q. DOES DEP NEED TO PREPARE A SPECIFIC PLAN TO HELP CUSTOMERS MITIGATE THE IMPACT OF COVID-19?

A. Because Duke has launched a corporate strategy to address the needs of customers in the aftermath of the pandemic, DEP does not need to file an EE-specific plan. While the Company had to suspend some programs temporarily, almost all programs have resumed full operations with additional safety protocols. Only two programs have not resumed due to their increase risk to customers and contractors, Neighborhood Energy Saver and Multifamily Direct Install. The Company is working with its vendors to resume once risks can be appropriately mitigated.

Q. WHY HAS DEP NOT ADJUSTED 2021 SAVINGS PROJECTIONS IN LIGHT OF THE PANDEMIC?

A. The Company set projections based on staffing and achievable energy savings potential in the market, neither of which has substantially changed as a result of the COVID pandemic.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1252

In the Matter of	)	
Application of Duke Energy Progress, LLC	)	**REBUTTAL TESTIMONY**
for Approval of Demand-Side Management	)	**OF TIMOTHY J. DUFF**
and Energy Efficiency Cost Recovery Rider	)	**FOR DUKE ENERGY PROGRESS,**
Pursuant to N.C. Gen. Stat. § 62-133.9 and	)	**LLC**
Commission Rule R8-69	)	

Q. MR. DUFF, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Timothy J. Duff. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services LLC as General Manager, Customer Regulatory Strategy and Evaluation.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Michigan State University with a Bachelor of Arts in Political Economics and a Bachelor of Arts in Business Administration, and received a Master of Business Administration degree from the Stephen M. Ross School of Business at the University of Michigan. I started my career with Ford Motor Company and worked in a variety of roles within the company's financial organization, including Operations Financial Analyst and Budget Rent-A-Car Account Controller. After five years at Ford Motor Company, I started working with Cinergy in 2001, providing business and financial support to plant operating staff. Eighteen months later I joined Cinergy's Rates Department, where I provided revenue requirement analytics and general rate support for the company's transfer of three generating plants. After my time in the Rates Department, I spent a short period of time in the Environmental Strategy Department, and then I joined Cinergy's Regulatory and Legislative Strategy Department. After Cinergy merged with Duke Energy Corporation ("Duke Energy") in 2006, I was employed as Managing Director, Federal Regulatory

Policy. In this role, I was primarily responsible for developing and advocating Duke Energy's policy positions with the Federal Energy Regulatory Commission. I became General Manager, Energy Efficiency & Smart Grid Policy and Collaboration in 2010, was named General Manager, Retail Customer and Regulatory Strategy in 2011, and assumed my current position of General Manager, Customer Regulatory Strategy and Evaluation in 2013.

Q. PLEASE DESCRIBE YOUR DUTIES AS GENERAL MANAGER, CUSTOMER REGULATORY STRATEGY AND EVALUATION.

A. I am responsible for the development of strategies and policies related to energy efficiency and other retail products and services. I also oversee the analytics functions associated with evaluating and tracking the performance of Duke Energy's retail products and services.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR ANY OTHER REGULATORY BODIES?

A. Yes. I testified in Duke Energy Carolinas, LLC's ("DEC" or the "Company") applications to update its demand-side management ("DSM") and energy efficiency ("EE") cost recovery rider, Rider EE, in Docket Nos. E-7, Subs 941, 979, 1001, 1031, 1050, 1130, 1164, and 1230, as well as the Company's application for approval of its new portfolio of DSM and EE program and new cost recovery mechanism in Docket No. E-7, Sub 1032. I also provided Supplemental Testimony in Duke Energy Progress, LLC's ("DEP") DSM/EE rider proceeding in Docket No. E-2, Sub 1145 and Rebuttal Testimony in Docket E-2, Sub 1174. In addition, I provided Rebuttal Testimony in DEP's

Renewable Energy Portfolio Standard Compliance Report in Docket No. E-2, Sub 1109. In addition to testifying on behalf of DEC and DEP in North Carolina, I also testified in South Carolina in Docket 2013-298-E in support of the Company's application for approval of its new portfolio of DSM and EE programs and new cost recovery mechanism. Beyond providing testimony in the Carolinas, I also have testified in matters pertaining to DSM and EE before the state regulatory commissions in the other four states in which Duke Energy subsidiaries provide utility service: Florida, Indiana, Kentucky and Ohio.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to address the Public Staff's recommendations, as described in the testimony of Public Staff witness John R. Hinton, that the avoided capacity cost benefits for purposes of the Portfolio Performance Incentive ("PPI") and cost-effectiveness of the Company's legacy DSM programs be calculated using a seasonal allocation of avoided capacity value. Witness Hinton's testimony also disagrees with the Company's application of a reserve margin factor in calculating the avoided cost value of energy efficiency programs. In my testimony, I will discuss why the Company's allocation of 100% of avoided capacity to legacy summer DSM resources is reasonable, consistent with past Commission Orders, and aligns with both North Carolina public policy and resource planning assumptions. I will also discuss why the Company's application of a reserve margin to the avoided capacity costs for EE programs is consistent with past Commission-approved practices and how EE resources are treated in the Company's approved Integrated Resource Plan.

Q. MR. DUFF, WILL YOU PLEASE SUMMARIZE THE AGREEMENT DEP REACHED WITH THE PUBLIC STAFF IN SUB 1145?

A. In pertinent part, the agreement establishes, beginning with Vintage 2019 and for all future Vintages, a uniform method for determining cost-effectiveness for DSM/EE programs and calculating the Company's PPI for the purposes of both the projection and true-up of programs offered in a given Vintage Year. Under this method, the Company uses the projected avoided capacity and energy benefits specifically calculated for the program, as derived from the underlying resource plan, production cost model, and cost inputs used to determine the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of December 31 of the year immediately preceding the date of the annual DSM/EE rider in which the Vintage was projected. The agreement specifies that the PURPA based avoided energy costs are derived by taking the difference between one production cost run that includes an assumed 24x7, 100 megawatts ("MW") of no-cost qualified facility ("QF") energy and one without the 100 MW of QF energy. The avoided energy costs used in the revised cost recovery mechanism are derived by taking a similar differencing approach, except the projected hourly load shapes and load reductions associated with the proposed bundle of DSM/EE programs would replace the 100 MW of no-cost QF energy. In order to ensure that new program requests and existing programs are being evaluated with up-to-date avoided costs, the agreement also establishes that the Company shall use projected avoided capacity and energy benefits specifically calculated for the program, as derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of the date of the filing for the new program approval. The Commission approved this agreement and the resulting revisions to the Company's cost recovery mechanism in the Sub 1145 Order.

Q. WHY DID THE COMPANY AND PUBLIC STAFF PROPOSE THESE CHANGES TO THE MECHANISM?

A. One of the primary purposes for the revisions to the mechanism was to eliminate the previous "trigger" approach for updating avoided costs. Prior to the changes approved in Sub 1145, the previous version of DEP's DSM/EE cost recovery mechanism provided that the per kW avoided capacity costs used to calculate the avoided cost savings were those reflected in the filing by DEP in Docket No. E-100, Sub 140 (the 2014 Biennial Avoided Cost Proceeding). The per kilowatt-hour ("kWh") avoided energy costs were those reflected in the Company's most recent integrated resource plan ("IRP") at the time that version of the mechanism was approved (the 2015 IRP). These avoided costs were only updated if certain triggers were hit – if avoided energy costs calculated for purposes of the IRP increased or decreased by 20% or more, or if avoided capacity costs reflected in the rates approved in the biennial avoided cost proceedings increased or decreased by 15% or more.

Under the old trigger approach, if the trigger thresholds were not hit, avoided cost rates could potentially remain unchanged for years. Under the agreement and approved modifications to the mechanism, these triggers are eliminated, and instead, DSM and EE programs are evaluated for cost effectiveness utilizing avoided cost rates that are based on the Commission-approved biennial avoided cost proceeding.

The second primary purpose of the agreement is that it changed the source and methodology for calculating avoided energy costs, which previously had been based on the IRP, so that like avoided capacity costs, avoided energy costs would now be derived from the biennial avoided cost proceeding. Absent the revision, the existing language in the mechanism could have resulted in DSM and EE programs being evaluated using avoided energy rates from the Company's IRP that were not based on the same fundamental assumptions used in the determination of the avoided capacity rates, which are based on the fundamental assumptions approved in the Company's biennial avoided cost proceeding. This potential mismatch could have undermined the validity of the cost effectiveness evaluation. The new language eliminates this potential problem by aligning the assumptions approved for both avoided energy and avoided capacity rates, as the proposed revisions to the mechanism call for using the most recently approved avoided energy cost and most recently approved avoided capacity cost derived from the same proceeding – i.e., the Company's biennial avoided cost proceeding.

Q. DID THE REVISIONS TO THE MECHANISM APPROVED IN SUB 1145 CHANGE THE METHODOLOGY BY WHICH THE COMPANY WAS TO CALCULATE AVOIDED CAPACITY COSTS?

A. No, aside from eliminating the trigger approach, there were no changes to the source or methodology underlying the avoided capacity calculation.

Q. WHAT WAS THE DATA SOURCE FROM WHICH THE COMPANY DERIVED THE AVOIDED CAPACITY RATE AND AVOIDED ENERGY RATE USED IN THE COMPANY'S APPLICATION IN THIS PROCEEDING?

A. Consistent with the revisions to DEP's DSM/EE cost recovery mechanism that the Commission approved in its Sub 1145 Order, the Company derived both the avoided energy and avoided capacity using the underlying resource plan, production cost model, and cost inputs approved in the Company's most recent avoided cost proceeding, which in this case is Docket No. E-100, Sub 158. Notably, the final order from the Commission in Docket No. E-100, Sub 158 was not issued until April 15, 2020, after the required December 31 deadline; however, the Company chose to implement the final proposed values in anticipation of the final approval and consistent with the Commission's October 2019 Notice of Decision in Docket No. E-100, Sub 158.

Seasonal Allocation Factor

Q. FOR PURPOSES OF THIS DISCUSSION, WHAT DOES THE COMPANY MEAN WHEN IT REFERS TO ITS "LEGACY" DSM PROGRAMS?

A. "Legacy" in this context and for this proceeding means the capacity resource that has been built from historic and planned DSM programs, or, in other words, the amount of DSM capacity included in the Company's 2018 IRP forecast as a load serving resource. Incremental or new DSM capacity refers to capacity resources that are built from new participation in DSM programs that was not factored into the Company's IRP forecast as a load serving resource.

Q. PLEASE EXPLAIN HOW THE COMPANY CALCULATED THE AVOIDED CAPACITY COST RATE ASSOCIATED WITH ITS LEGACY DSM PROGRAMS.

A. The Company utilized the avoided capacity value calculated using the Peaker Method consistent with the Sub 1145 Agreement and the Commission's recent DSM/EE cost-recovery orders, including the Commission's *Order Approving DSM/EE Rider and Requiring Filing of Customer Notice*, issued on November 29, 2018 in Docket No. E-2, Sub 1174.

Q. DID THE COMPANY EXPECT THE PUBLIC STAFF TO ADOPT THE POSITION THAT THE REVISIONS TO THE COMPANY'S DSM/EE COST RECOVERY MECHANISM APPROVED IN THE DOCKET NO. E-2, SUB 1145 ORDER WOULD ALTER THE WAY AVOIDED

CAPACITY ASSOCIATED WITH LEGACY DSM RESOURCES WAS TO BE UPDATED?

A. No, the Company did not believe the Sub 1145 Agreement's revisions to the mechanism would amend how the Company calculates the avoided capacity costs used to evaluate existing programs that have already been approved by the Commission, are part of the Company's existing portfolio of programs and have been factored into the Company's IRP.

Q. DO YOU BELIEVE THAT THE COMPANY'S APPLICATION OF THE UPDATED AVOIDED CAPACITY RATES APPROVED IN DOCKET NO. E-100 SUB 158 IS CONSISTENT WITH THE AGREEMENT IN DOCKET NO. E-2, SUB 1145 AND VALIDATED AND APPROVED IN DOCKET NO. E-2, SUB 1174?

A. Yes, the avoided capacity cost used in determining the projected Vintage 2021 cost effectiveness and PPI was calculated consistently with both the Company's most recent annual DSM/EE cost recovery proceeding in Docket No. E-2, Sub 1174 and with the Sub 1145 Agreement. To recognize the growing need for winter capacity and to encourage EE and DSM programs that will provide winter capacity savings, however, the Company made one change to its application of avoided capacity costs in this proceeding from previous proceedings. Beginning with Vintage 2021, the Company voluntarily applied the 100% Winter allocation approved in the most recent avoided cost proceeding to avoided capacity savings for all new incremental participation in EE Programs and new incremental participation in DSM programs where the projected DSM summer peak capability exceeds the levels forecasted in the 2018 IRP. The Company believes this approach is consistent with the treatment of new QF capacity as discussed in the Commission's Notice of Decision and April 15, 2020 *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* in Docket No. E-100, Sub 158 ("Sub 158 Order"). Furthermore, although the Commission's discussion of its findings and conclusions in the Sub 158 Order were not before the Company when it filed this DSM/EE application, the Company's adjustment to its avoided capacity savings in this proceeding is consistent with the Commission's encouraging Duke to place additional emphasis on defining and implementing cost-effective DSM programs that will be available to respond to winter demands.

Q. WHAT DID THE COMMISSION CONCLUDE ABOUT SEASONAL ALLOCATIONS IN THE PREVIOUS AVOIDED COST PROCEEDING?

A. The Commission concluded that DEP's seasonal allocation weightings for future capacity need of 100% for winter and 0% for summer were appropriate for use in weighting capacity value between winter and summer.[1] In so concluding, the Commission acknowledged that the currently high solar penetrations in DEP's service territory that it expects to continue in the future will have different impacts on summer versus winter loads net of solar contribution than in the past.[2]

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[1] Sub 158 Order at 28.

[2] *Id.*

Q. WAS THE COMPANY REQUIRED TO ADOPT THIS SEASONAL ALLOCATION TO NEW INCREMENTAL PROGRAMS AND PARTICIPATION BY THE COMMISSION'S SUB 158 ORDER AND SUB 1145 AGREEMENT?

A. No, neither the Commission's previous avoided cost order, Sub 158, nor the Sub 1145 Agreement expressly required adoption of this seasonal allocation for purposes of this cost-recovery proceeding. As I mentioned previously, the Company *voluntarily* adopted the recently approved seasonal allocation of avoided capacity values for new incremental programs and participation in this proceeding to encourage the development and specific promotion of EE and DSM programs that provide winter capacity savings. Additionally, the Company feels that adopting this seasonal allocation approach better aligns with how new qualifying facilities ("QFs") receive capacity value consistent with the Sub 158 Order. Although this is the first time the Company has applied a seasonal allocation factor to new incremental programs and participation for this purpose, the reality is that the Commission's order in the Docket No. E-100, Sub 148 Avoided Cost Proceeding also included a seasonal allocation for capacity of 80% for winter and 20% for summer. Neither the Company nor any party to the previous DSM/EE proceedings, however, raised the argument after the Docket No. E-100, Sub 148 Avoided Cost Proceeding that the Sub 1145 Agreement required the Company to apply those Sub 148 seasonal allocations to the EE and DSM programs. The Company voluntarily applied the seasonal allocation to incremental new participation in both EE and DSM programs for the first time in this proceeding for the reasons previously mentioned.

Q. DO YOU BELIEVE THAT THE COMPANY'S APPLICATION OF THE SEASONAL ALLOCATION FACTOR ONLY TO NEW AND INCREMENTAL DEMAND RESPONSE PROGRAMS IS APPROPRIATE?

A. Yes, the Company believes that it is appropriate and consistent to only apply the seasonal allocation factor to new and incremental Summer DSM program participation that was not factored into the Company's IRP while at the same time continuing to recognize 100% of the avoided capacity value of the Company's legacy summer demand response programs.

Q. WHY DOES THE COMPANY BELIEVE THAT LINKING TREATMENT OF LEGACY DSM PROGRAMS AND TREATMENT OF EXISTING QFS WITH RESPECT TO APPLICATION OF THE COMMISSION'S AVOIDED COST DETERMINATIONS IS APPROPRIATE IN THIS PROCEEDING?

A. The Commission has previously concluded that the net benefits and financial incentives for DEP's DSM/EE programs are linked (although not identical) to the avoided cost rates DEP pays QFs for avoided energy and capacity. As the Commission itself noted in its Sub 158 Order, seasonal allocation factors may change based on the then prevailing circumstances reviewed in biennial avoided cost proceedings.[3] Therefore, just as the Commission approved applying the

[3] Sub 158 Order at 28.

seasonal allocation factors of 100% winter and 0% summer to future QF capacity in its order in Docket No. E-100, Sub 158, the Company applied the approved seasonal allocation factors to new and incremental demand response programs in this proceeding. As a corollary, just as the Commission did not retroactively apply its Sub 158 seasonal allocation factors to QFs that had previously established power purchase agreements ("PPAs") at avoided cost rates that were approved based on past prevailing circumstances, the Company did not retroactively apply the seasonal allocations approved in Sub 158 to its legacy DSM programs.

Additionally, the Commission's review of the Company's 2018 DSM/EE application supports the Company's treatment of its legacy DSM/EE in this proceeding. In the 2018 DSM/EE cost recovery proceeding, Docket No. E-2, Sub 1174, the Public Staff asserted that legacy DSM programs should receive zero capacity value until the year of first need shown in the Company's most recent IRP, based on the Commission's avoided cost determination in Docket No. E-100, Sub 148 and House Bill 589's recent amendments to N.C. Gen. Stat. §62-156(b)(3). The Company opposed this recommendation and argued, among other things, that the MW reductions of those programs were already included in the IRP and that the policy reasons behind this shift in the Commission's PURPA implementation in Docket No. E-100, Sub 148 did not likewise compel the Commission to duplicate application of the zero capacity value to existing DSM/EE programs. The Company also noted that its DSM programs had been established over a number of years and were a useful resource and that legacy DSM programs should be treated similarly to QFs that had established legally enforceable obligations ("LEOs") or had signed PPAs prior to November 15, 2016. In my Rebuttal Testimony in the case, I argued that, as the Commission or House Bill 589 had not retroactively ended the capacity payments for those QFs, the Commission should not discontinue attributing capacity value to legacy DSM programs.[4] The Commission declined to accept the Public Staff's recommendation and ruled that the Company's method of assigning full avoided capacity cost value in every year was correct. Thus, one of the main arguments that the Commission considered in its conclusion was that the treatment of existing legacy DSM programs as a resource could be linked to treatment of existing PPAs with QFs. I am not contending that existing legacy DSM capacity must be valued the same as existing QF capacity; instead my point is that, just as it would be improper and inconsistent with the Commission's policies under the Public Utility Regulatory Policies Act ("PURPA") to change the avoided capacity value for an existing QF, it would likewise be improper to change the avoided capacity value for an existing DSM resource. Accordingly, for purposes of this proceeding, it is appropriate to recognize the similarity between the continuing capacity value for these legacy summer DSM programs and QFs that had established LEOs or had signed PPAs with the Company.

Q. PLEASE DESCRIBE HOW FROM AN INTEGRATED RESOURCE PLANNING STANDPOINT THE LEGACY DSM PROGRAMS,

[4] NCUC Final Order, Docket No. E-2, Sub 1174 at 27-28.

SPECIFICALLY THE POWER MANAGER PROGRAM, ARE VIEWED.

A. From the perspective of the Company's IRP, the Company's Legacy DSM Programs are considered a dispatchable resource that is available for the entire fifteen-year IRP planning horizon. In particular, the EnergyWise Program resource has the flexibility to dispatch any time throughout the day depending on the net load on the system after accounting for must-take solar output onto the grid. As such, EnergyWise is available to dispatch into the evening hours when net load is still high due to diminished solar output, a phenomenon often referred to as the "duck-curve." Conversely, if solar is lost due to mid-afternoon cloud cover, Demand Response Programs can be utilized earlier to make up for diminished irradiance. As an IRP resource, both existing DR programs that control air conditioning load and existing solar resources are oriented toward summer peak demand reduction helping to meet consumer peak demand in the summer. This summer capacity value from these resources, at least in part, is why incremental resource decisions are now geared toward winter peak demand needs. Importantly, this does not imply that existing summer-oriented resources such as EnergyWise that controls air conditioning load and QF solar are not valuable, but rather implies that incremental additions to such resources would have diminished incremental value.

Q. DOES WITNESS HINTON ATTEMPT TO SUPPORT HIS CONTENTION REGARDING THE NEED TO APPLY THE SEASONAL ALLOCATION TO LEGACY RESOURCE AS HE DID IN

DOCKET E-7, SUB 1230 BY CONTENDING THAT DSM RESOURCES IN THE LEGACY DSM PROGRAMS ARE SHORT-LIVED AND HENCE EACH YEAR'S CUSTOMER PARTICIPATION IS NEW AND INCREMENTAL?

A. No, he does not make a similar contention. As pointed out by the Company in the recent DEC DSM/EE rider proceeding, Docket No. E-7, Sub 1230 ("Sub 1230 proceeding"), although DEC and DEP utilize similar hardware on the residential side and similar contractual agreements on the non-residential side with respect to their legacy DSM programs, due to the structure of the DEP recovery mechanism, DEP recognizes a twenty-five year measure life versus the one-year used by DEC. For this reason, Mr. Hinton does not contend they are short-lived. The fact is that while the Company recognizes one year of participation at a time in its cost recovery, the legacy DSM resource has been built over time, and the term of implicit contract with customers likely more closely resembles the life of the load control switch than it does a one-year measure life. Moreover, based on the Company's experience, the Company's legacy DSM program retains customers year after year, experiencing only about a 1% annual net attrition rate after factoring in that, in the vast majority of the residences where an existing DSM-participating customer moves out, the new customer in that residence chooses to continue participation in the DSM program.

In addition, from a system planning perspective, the peak MW capability of the DSM programs is included for all 15 years of the IRP. In fact, as noted in the

Commission Order in Docket No. E-7, Sub 1164, Public Staff Witness Williams acknowledged that the DSM programs in the DSM/EE IRP block are "stable and expected to continue for the foreseeable future".

Q. WITNESS HINTON STATES THAT HE BELIEVES THAT THE CAPACITY VALUE OF SUMMER DSM RESOURCES HAS CHANGED DUE TO CHANGES IN THE COMPANY'S SYSTEM LAMBDA. DO YOU AGREE WITH THIS ASSESSMENT?

A. No, I do not. With his confidential testimony on the Company's system lambda, it appears that witness Hinton is attempting to show that during the most recent four years of actual DSM activations, the Company has had fewer activations of summer DSM programs, which he attributes to a change in the Company's system lambda. Although it is true that the metric Mr. Hinton is using, the Company's system lambda, appears to show that the expected avoided energy costs during peak summer hours have become lower over time, this type of behavior in avoided energy costs does not clearly refute the Company's legacy DSM summer capacity value or justify reducing its value now. This change in the summer avoided costs could just as easily be explained by the milder 2017-19 summers when compared to the summer of 2016 where the DSM programs were activated a significant number of times. The Company has not performed a rigorous analysis of the Cooling Degree Days during these summer periods versus a weather normal period. A cursory examination of historical temperatures, however, indicates that the summer of 2016 was much hotter than normal. In contrast, the 2017-19 summers were very close to normal summer periods.

Additionally, the full value of a summer DSM resource occurs during extreme weather days where that ability to dispatch a summer DSM program provides peak load reduction that is less expensive than starting up and running more expensive peaking generation. Thus attempting to show that summer DSM has become less valuable over time by highlighting system lambdas during normal weather years (2017-19) when compared to an extremely hot summer year is misleading.

Q. DO YOU AGREE WITH WITNESS HINTON'S CONTENTION THAT RECOGNIZING THE SEASONAL ALLOCATED CAPACITY VALUE OF 0% ON ITS LEGACY DEMAND RESPONSE PROGRAMS WOULD BETTER ENCOURAGE THE COMPANY TO PROMOTE WINTER CAPACITY FOCUSED EE AND DSM PROGRAMS?

A. No. While as stated previously, the Company agrees that recognizing a seasonal capacity allocation factor applied to new and incremental EE and DSM programs and participation will encourage the Company's portfolio to achieve more winter capacity savings, it struggles to understand how devaluing an existing approved summer resource that is heavily relied upon in system planning in any way encourages more winter capacity savings. The reality is that the recognition of full capacity value for an existing Summer legacy resource has virtually no influence on the value or emphasis placed on a promoting new participation and savings in a Winter Resource; they are in fact independent of each other. Furthermore, the Company has recently filed and asked for expedited approval of a winter-focused modification to its Residential Service Load Control for approval in Docket No. E-2, Sub 927, without having to resort to the Public Staff's extreme position of devaluing legacy summer resources.

Q. DO YOU AGREE WITH WITNESS HINTON'S CONTENTION THAT APPLYING THE SEASONAL ALLOCATION FACTOR TO LEGACY DSM PROGRAMS SHOULD NOT MATTER BECAUSE THE PROGRAMS STILL PROJECT TO BE COST EFFECTIVE EVEN AFTER SUCH AN APPLICATION WOULD OCCUR?

A. No, I do not agree. While Mr. Hinton is correct that the Company's legacy DSM programs appear to project to be cost effective for Vintage Year 2021 if the 0% seasonal allocation factor is applied, if when one looks more closely at the legacy participation in the Company's Commercial, Industrial and Governmental Demand Response Automation Program (CIG-DRA), it becomes clear that adopting Mr. Hinton's recommendation would impact cost effectiveness for measures within the program and hence the summer capacity resources available from the program. The program level cost-effectiveness analysis presented in Public Staff witness Williamson's Exhibit 4 that is referenced by witness Hinton reflects a blend of year-round and summer-only participants in the program. What is not shown in this analysis is that about 9 MW of the 27 MW of legacy summer capacity is associated with 37 customers that are under summer-only contracts. Following the Public Staff's recommendation regarding seasonal allocation to legacy DR programs would in fact reduce the Utility Cost Test of these summer-only participants to 0.65 and put into question the prudence of maintaining approximately 33% of the legacy summer capacity resource that has been included in DEP's IRP. Beyond this specific impact to the CIGDRA program, adopting witness Hinton's recommendation will have broader longer-term impacts on this important legacy summer capacity resource.

First, as discussed earlier, failure to factor in the full avoided capacity is simply not correct, as the legacy DSM programs were implemented assuming that the avoided capacity value would exist in the Company's IRP documents where the contribution from DSM programs is included in all 15 years of system planning analysis.

Second, Mr. Hinton correctly claims that, with no avoided capacity value being recognized, the avoided costs associated with the legacy resource must come from avoided Transmission and Distribution ("T&D") value. These avoided T&D rates are required by the Commission to be studied and updated prior to 2022. Given the uncertainty regarding the avoided T&D values beyond 2021, the Company does not believe it is appropriate to adopt Mr. Hinton's short-sighted justification that the unwarranted application of the seasonal allocation factor to the avoided capacity associated with legacy DSM resources is appropriate because the programs project to be cost effective in 2021. By establishing a precedent that the avoided capacity value for these existing summer DSM resources is arbitrarily reduced to 0%, this could easily create a situation where these programs are no longer cost effective if there is a drop in the avoided T&D values.

Finally, in the Commission's final order in Docket No. E-2, Sub 1174, the Commission stated that it was "persuaded by the arguments of DEP, and NC Justice Center that assigning a zero capacity value to DSM programs would under-value the contributions of those programs and send the wrong pricing signal." In the same way, it logically follows that assigning a 0% value for avoided capacity to an existing summer DSM resource would under-value the value of this capacity resource.

Reserve Margin

Q. DO YOU AGREE WITH WITNESS HINTON'S CONTENTION THAT IT IS INAPPROPRIATE FOR THE COMPANY TO APPLY A RESERVE MARGIN FACTOR IN THE DETERMINATION OF THE AVOIDED COST VALUE ASSOCIATED WITH THE COMPANY'S EE PROGRAMS FOR VINTAGE 2021?

A. No, I do not agree. Because EE is treated as a load reduction resource in the IRP, rather than as a load serving resource, it is appropriate that it should have a 17% reserve margin factor applied, just as it would be appropriate to apply a 17% planning reserve margin factor to an increase to the system load. For every KW of load reduction that comes from EE, the Company does not need to plan for 1.17 KW of load serving capacity. For this reason, it is both mathematically logical and prudent from a planning standpoint to apply a 17% reserve margin factor to the avoided capacity associated with EE programs.

Q. HAS DEP PREVIOUSLY INCLUDED A RESERVE MARGIN ADJUSTMENT IN THE DETERMINATION OF THE AVOIDED COST VALUE ASSOCIATED WITH THE COMPANY'S EE PROGRAMS ?

A. Yes, it has. As discussed in DEC's recent DSM/EE rider proceeding where this issue also arose and as acknowledged by witness Hinton in this proceeding, the Company has included a reserve margin adjustment before to model EE cost-effectiveness.

Q. DO YOU AGREE WITH WITNESS HINTON'S TESTIMONY REGARDING DEP'S INCLUSION OF A RESERVE MARGIN ADJUSTMENT PRIOR TO THE 2012 MERGER OF DUKE ENERGY CORPORATION AND PROGRESS ENERGY, INC.?

A. Yes, but in reality the inclusion of such an adjustment continued beyond the 2012 merger. For all vintage years through 2014, DEP used the Strategist model to perform EE cost-effectiveness evaluations. Strategist included a variable for annual peak kW savings and a variable called deferred generation, which multiplied a reserve margin factor of (1 + planned reserve margin) times the annual peak kW savings. Beginning with vintage year 2015, DEP began using the DSMore tool for cost-effectiveness evaluations, but all of the avoided cost inputs used for that vintage year continued to use the Strategist-based avoided costs, which included the adjustment for deferred generation described above. It was not until vintage year 2016 that DEP started using DSMore with new avoided energy and capacity costs based on the 2014 Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from QFs proceeding. The avoided capacity rates in that proceeding included a 1.20 performance adjustment factor ("PAF"), which was also referred to as a 20% reserve margin adjustment, so it was no longer necessary for DEP to include its own reserve margin adjustment factor.

Q. WHY DOES DEP BELIEVE THE INCLUSION OF A RESERVE MARGIN ADJUSTMENT IS AGAIN NECESSARY AND APPROPRIATE IN THIS PROCEEDING?

A. The PAF was lowered from 1.20 to 1.05 in the 2016 Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from QFs proceeding, so instead of representing a 20% reserve margin adjustment, it is now only intended to account for a 5% forced outage rate. Also, because DEP's IRP process treats EE peak load savings as a reduction to the load forecast, it is appropriate to recognize that the impact on avoided capacity is actually greater than the peak load savings by the amount of DEP's planned reserve margin.

Q. IF THE PAF WAS LOWERED IN THE 2016 AVOIDED COST PROCEEDING, WHY DID THE COMPANY WAIT UNTIL THIS PROCEEDING TO INCLUDE THIS RESERVE MARGIN ADJUSTMENT?

A. After several successive years of no substantive changes in avoided cost methodologies, the 2016 Avoided Cost Proceeding resulted in many changes to the Commission's PURPA policies, including revision of the PAF. The Commission issued its *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities* on October 11, 2017 in Docket No. E-100, Sub 148, outlining these changes. When the Company first applied the approved avoided cost rates in 2018, the Company unfortunately missed this adjustment in the transition to the new avoided cost policies. The Company has included the adjustment in this proceeding, however, because it is necessary to reflect the system value of capacity savings associated with energy efficiency.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING WITNESS HINTON'S DISCUSSION OF THE APPLICATION OF A 17% RESERVE MARGIN TO THE AVOIDED CAPACITY ASSOCIATED WITH EE PROGRAMS?

A. Yes. I have several additional comments and concerns with witness Hinton's testimony.

First, Mr. Hinton states on Page 5 lines 19 through Page 6, line 2 that the reserve margin adjustment was applied by the Company to "all of the megawatt (MW) reductions (demand reduction benefits) associated with the Company's EE programs beginning with vintage year 2021." This statement requires clarification that the Company only applied the adjustment to the avoided capacity benefits, not the avoided T&D benefits. Technically, a reduction in avoided T&D costs could also be considered a demand reduction benefit, and the Company wants to clarify that the reserve margin adjustment is only applied to the reduction in avoided capacity.

Second, on Page 12 , lines 21 through 24 of Mr. Hinton's testimony he states, " Additionally, the Company's proposal effectively increases what customers will pay for the avoided capacity cost benefits of the EE programs by increasing the avoided capacity cost rate above the approved rate." This statement, along with his contention that the Company is using an avoided capacity rate that is inconsistent with the methodology spelled out in paragraph 70 of the recovery mechanism approved in Docket E-2, Sub 1145, is inaccurate. The Company's application of the 17% reserve margin to capacity savings associated with EE programs impacts but does not change the avoided capacity rate applied to savings but rather the amount of capacity savings that are recognized from a EE Program. Mr. Hinton's attempt to confuse the issue between the magnitude of the capacity savings recognized through an EE Program, and the rate applied to the savings, ignores the symmetrical impact that the Company's proposal has on supply side resources required, not the rate applied to them. In other words, he ignores the fact that the Company's application of the reserve margin to the avoided capacity associated with EE Savings does not impact the avoided capacity rate applied to supply side resources in the resource plan, but rather reduces the magnitude of the supply side resources needed in the plan.

Third, Mr. Hinton states on Page 10, lines 10-12 of his testimony that "This enhanced value is not realized from the customer's perspective in the short-run and it is not entirely clear whether the customer(s) will realize any value in the long-run." This statement is not correct. Simply because the 2018 IRP shows DEP's actual reserve margin is equal to more than 17% in the near-term does not mean that there is no capacity value to building new EE resources several years before the in-service date of a new generating unit. The majority of the EE measures in DEP's vintage 2021 portfolio have a life greater than 6 years, which is about the time DEP's 2018 IRP includes the need for new combustion turbine generation. Therefore, those EE measures with longer lives directly contribute peak load and reserve margin savings during and after the in-service date of the next planned generating unit. EE programs are built one customer or one measure (e.g., one LED light bulb) at a time, so it typically takes several years to build a significant amount of peak load savings from EE resources. As such, EE needs to start being implemented well in advance of when it is needed. Fourth, in his example on page on Page 9 lines 4-20 and page 10 lines 1-4, Mr. Hinton contends that he illustrates the effect of shifting 100 MW from a demand-side EE resource to a supply-side resource, which he says leads to a 17.7% reserve margin. His example ignores the reality that DEP's proposal is about using demand-side EE resources to reduce the load forecast and thereby reduce the need for supply-side capacity, not about shifting load from one type of resource to another. Using witness Hinton's example from DEP's 2018 IRP, a 100 MW increase in EE would reduce the 2021 peak load forecast from 14,151 MW to 14,051, which would allow supply-side capacity needs to be reduced by 117 MW (from 16,555 MW to 16,438 MW) in order to maintain the same 2021 reserve margin of 17%. The key point is that the savings from demand-side EE resources not only acts to reduce the load forecast, but it also eliminates the need to build a 17% reserve margin on that savings.

Fifth, on page 10, lines 4-6 of Mr. Hinton's testimony, he states that, "A weakness in DEP's argument is the inequity of asking customers to pay 17% more for the same MW reduction from an EE program, as compared to a MW reduction from a DSM program." The Company disagrees with this statement because the IRP addresses EE programs differently than DSM programs. Because the IRP treats EE program as a reduction to the load forecast, EE programs also eliminate the need to build a reserve, which is why EE programs should include the 1.17 reserve margin adjustment factor. DSM programs, on the other hand, are treated as a dispatchable resource, much like a generating unit. As such, DSM programs are recognized within the IRP as additional supply-side capacity, not as a peak load reduction to the load forecast. If there is no load forecast reduction, then there are also no reserve margin savings. Thus, DEP's proposal is both the correct and equitable solution, and the fact that it properly recognizes this important distinction is a strength, not a weakness.

Finally, Mr. Hinton argues that "…this is not the appropriate proceeding to evaluate such a significant change to the avoided capacity costs" as stated on Page 14, lines 6-7. As discussed earlier, however, the Company does not believe that the application of the reserve margin adjustment is a change. Instead it is consistent with the past practices employed by the Company. As shown in Duff Rebuttal Exhibit 1, the Company has made clear in the past that a reserve margin adjustment was being appropriately utilized in the determination in the magnitude of the avoided capacity savings associated with EE Programs.

Q. IF THE COMMISSION AGREES WITH WITNESS HINTON'S CONTENTION THAT THE PAF UTILIZED IN THE

DETERMINATION OF THE COMPANY'S AVOIDED CAPACITY RATES APPROPRIATELY REFLECTS A RESERVE MARGIN, AND NOT SIMPLY AN EFFECTIVE FORCED OUTAGE RATE, SHOULD THE COMPANY BE REQUIRED TO REMOVE THE 17% RESERVE MARGIN ADDER IT APPLIED TO AVOIDED CAPACITY ASSOCIATED WITH EE PROGRAMS?

A. No, even if the Commission determines that the PAF included in avoided capacity calculations was equivalent to a reserve margin adjustment, it would only account for a portion of the appropriate adjustment for the reserve margin associated with avoided capacity coming from EE programs. In other words, an appropriate adjustment would be to only apply an 11.429% reserve margin adder (Reserve Margin/PAF or 1.17/1.05) to the avoided capacity to make the capacity reduction reflect a 17% reserve margin after factoring the 5% PAF already factored into the Company's approved avoided capacity rate in Docket No. E-100, Sub 158.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

<u>Duke Energy Response to Public Staff Data Request in Docket E-2 Sub 1070</u>

Question: DEP PS DR21-4

Request Date: 8/12/2015

Due Date: 8/21/2015

Question:

In response to Item 1, please provide detailed support for the 14.50% adjustment in the avoided capacity rates to accommodate the transition from Strategist to DSMore. This response should also identify whether the 1.2 performance adjustment factor is incorporated in the avoided capacity rate.

Answer:

Note: The last two sheets of the spreadsheet provided in response to Data Request No. 8, item 1 inadvertently placed a footnote (“Note: Reserve margin savings of 14.5% has been included in the avoided capacity rates rather than applied to the program's peak kW savings, to accommodate the transition from Strategist to DSMore.”) under the table showing vintage year 2016 avoided cost rates. That footnote does not apply to the vintage year 2016 avoided capacity rates in DSMore. The reserve margin savings was only included in the vintage year 2015 DSMore evaluations in order to match the same avoided capacity costs used in the Strategist-based vintage years of 2013-2014.

DEP uses a 14.5% minimum planned reserve margin for Integrated Resource Planning (IRP) purposes. Since demand-side programs serve to reduce customer peak demands, they provide both a system peak demand savings and a reserve margin savings. The sum of these two savings components represents the total amount of avoided capacity associated with a given program. DEP has recognized this total amount of avoided capacity for all vintage years shown in previously approved DSM/EE program filings.

Strategist-based evaluations applied the reserve margin savings component to the program’s coincident peak demand savings. For the vintage year 2015 DSMore evaluations, however, it was necessary to apply the 14.5% reserve margin savings factor to the avoided generation capacity cost rate. Given the multiplicative nature of the total avoided generation capacity cost calculation, both approaches yield identical results.

For vintage year 2016, the avoided capacity cost rate is from DEP’s most recently approved biennial (2012) avoided cost proceeding, which includes the 1.2 performance adjustment factor. Note that the last sentence of the response to Data Request 8, Item 4 incorrectly listed the year of the avoided cost proceeding as "2014," while the docket number provided ("E-100, Sub 136") correctly identified the 2012 avoided cost proceeding.