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January 25, 2022

VIA ELECTRONIC FILING

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

RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Cost of Service Study Report
Docket Nos. E-7, Sub 1214 and E-2, Sub 1219

Dear Ms. Dunston:

Pursuant to the North Carolina Utilities Commission's March 31, 2021 *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* in Docket Nos. E-7, Sub 1214 et al. and its April 16, 2021 *Order Accepting Stipulations, Granting Partial Rate Increase and Requiring Customer Notice* in Docket Nos. E-2, Sub 1219 et al., enclosed for filing in the above referenced dockets is the Cost of Service Study per Stipulation in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

Enclosure

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Cost of Service Study per Stipulation, in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219, 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 25th day of January, 2022.

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Cost of Service Study per Stipulation in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214

January 25, 2022

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Regulatory Basis for this Analysis

Pursuant to the North Carolina Utilities Commission's (the "Commission") March 31, 2021 *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* in Docket No. E-7, Sub 1214 and its April 16, 2021 *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* in Docket No. E-2, Sub 1219 (collectively, the "Orders"), Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and collectively with DEC, the "Companies") have performed analyses of various cost of service study methodologies consistent with the terms of the Second Agreement and Stipulation of Partial Settlement entered into between the Public Staff and DEC and DEP, respectively (collectively, the "Second Partial Stipulations").

The Companies undertook analyses of additional cost of service studies subject to the following conditions set forth in the Second Partial Stipulations:

1. The Company agrees to analyze and develop cost of service studies based on each of the following methodologies:
   a. Single Summer Coincident Peak;
   b. Single Winter Coincident Peak;
   c. One that utilizes the four highest monthly system peaks (two monthly peaks in summer and two monthly peaks in winter);
   d. Summer/Winter Peak and Average ("SWPA");
   e. Base Intermediate and Peak (as Described in the RAP "Electric Cost Allocation for a New Era" manual published January 2020); since the Company's accounting systems do not have the data developed to produce such a study, this method may be analyzed by looking at how it has been used at another utility or with a higher level hypothetical analysis;
   f. One that utilizes the 12 highest monthly system peaks in the test year; and
   g. Any other identified relevant methodologies.
2. Each methodology studied will include an evaluation of the allocation of the functions of utility service (production plant, transmission plant, distribution plant, and customer costs), including an identification of which cost components associated with these functions of utility service are fixed, and which are variable costs of service. The

above methodologies only impact production and transmission allocations; however, the cost of service studies will show the allocation of all functions. For purposes of these studies, all demand and customer classified costs can be designated as fixed, and all energy classified costs can be designated as variable.

3. Each methodology studied will include an evaluation of its strengths and weaknesses on both a jurisdictional and class allocation basis.
4. Included in the studies shall be a discussion of how the allocation of fuel and other variable O&M expenses align with system planning.
5. The Company shall consult with the Public Staff and any other interested parties throughout the study process.

The Companies have undertaken this cost of service analysis with specific emphasis on production cost allocation methodologies.

The major events defining this study were as follows:

- June 2, 2021 – Duke Energy provided notice to parties of record in its DEC and DEP rate proceedings that it was undertaking the stipulated study and asked interested individuals to indicate their interest in participating.
- June 3, 2021 – Duke Energy informed the South Carolina Public Service Commission of this study and the Companies' intention to reach out to and include South Carolina stakeholders who have historically shown an interest in this topic.
- June 29, 2021 – Initial project stakeholder meeting was held to clarify the scope of the study and present the study timeline. After reviewing the list of methods to be evaluated, one of the stakeholders suggested the group also evaluate the Average & Excess method. Several agreed, and that method was added to the list to be studied.
- July 13, 2021 – A stakeholder meeting was held and the Companies presented the development of the four peak responsibility methods (1 Summer Coincident Peak ("CP"), 1 Winter CP, 4CP and 12CP), the Summer-Winter Peak and Average method, the Average & Excess method, the Average & Excess 4CP method and the Base,

Intermediate & Peaking method. The presentation also provided the resulting allocation factors for the North Carolina, South Carolina, and wholesale jurisdictions as well as the rate classes within the retail jurisdictions for both utilities. A stakeholder suggested the group investigate the Average & Excess method as implemented by Dominion Energy in its Virginia jurisdiction, which is different than the other Average & Excess methods reviewed. In response to comments from another stakeholder, it was pointed out that the issue of curtailable load was not within the scope of the study but would be addressed in a future rate case. Other stakeholders offered comments based on their observations of the allocation factor results.

- August 12, 2021 – A stakeholder meeting was held with a focus on the Average & Excess method as used by Dominion Energy and as requested by one of the study's stakeholders. In addition, a revised Base, Intermediate & Peaking method was introduced. Lastly, the rates of return by rate class resulting from the application of each allocation methodology were presented.
- September 14, 2021 – A stakeholder meeting was held with a focus on a method to allocate fuel expenses to rate classes instead of on a uniform cents per kWh basis. Tables were provided showing rates of return by rate class before and after the fuel adjustments. Lastly, an outline of the draft final report was presented. Following the meeting, the draft final report was sent to the study participants for comments.
- October 14, 2021 – A stakeholder meeting was held for the purpose of reviewing an initial draft of the stakeholder group's final report.
- November 16, 2021 – A second stakeholder meeting was held for the purpose of reviewing an updated draft of the stakeholder group's final report.

Introduction

The overall purpose of cost of service studies is to determine whether each class of customers is providing the utility with a reasonable level of revenue to recover the costs necessary to provide service to each customer class. Duke Energy utilizes an embedded cost of service approach where the majority of its plant investment and costs are incurred to serve all customers in a joint manner. To the extent that certain costs can be explicitly attributed to a specific group of customers, those costs will be directly assigned to those customers. Since most costs are jointly incurred to serve all customers, they must be allocated across all customer classes. To the maximum extent possible, joint costs are allocated to the customer classes based on the principle of cost causation[1]. The application of cost causation is greatly influenced by the methodology chosen for the cost of service study.

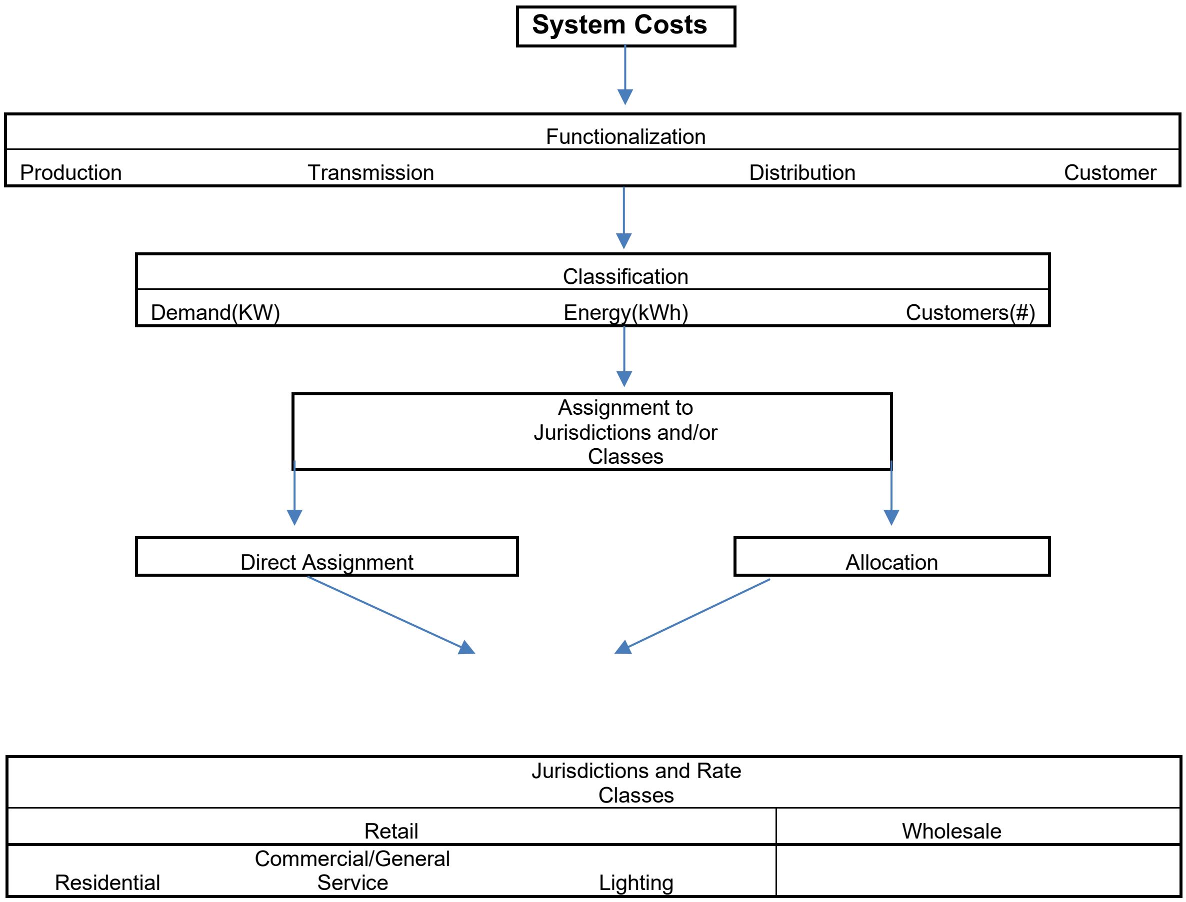
As a result, cost of service studies prepared for the same utility and for the same test period using different allocation methodologies will yield different results. In addition, a cost of service study prepared for the same utility and using the same allocation methodology, but a different test period, will yield different results as well.

The process of conducting a cost of service study involves three steps:

- functionalization
- classification
- allocation

[1] The "Cost Causation Principle" as defined by G.S. 62-133.16 (ratified October 13, 2021), means establishment of a causal link between a specific customer class, how that class uses the electric system, and costs incurred by the electric public utility for the provision of electric service.

The chart below provides a pictorial representation of this process in their order of occurrence.



The result is a revenue requirement by rate class that serves as a starting point for rate design, and a cost of service for the North Carolina or South Carolina retail jurisdiction that is a foundation for determining the overall jurisdictional revenue requirement.

Functionalization entails the sorting of plant investment and expenses by system component, such as production, transmission, distribution or customer operations. For the most part, the functionalization of costs follows the utility’s accounting system, which is based on the Federal Energy Regulatory Commission’s (“FERC”) Uniform System of Accounts. For example, FERC Account 312 is Boiler Plant Equipment. Boiler Plant Equipment is equipment used in the production of steam, to be used primarily for generating electricity. Therefore, FERC account 312 is functionalized as production.

Classification takes the functionalization step beyond the accounting records by identifying the primary driver of each cost. The three basic types of costs are:

1. Capacity-related costs incurred to ensure reliable service during periods of highest load.
2. Energy-related costs incurred to generate the energy that customers require over time.
3. Customer-related costs incurred to connect customers to the system, bill them and administer their service on an ongoing basis.

The allocation step involves the assignment or allocation of classified costs to the various jurisdictions and customer classes. One of the primary goals of a cost of service study is to develop rate class cost allocation factors that accurately reflect cost causation. Therefore, the allocation of costs is usually based on some measure of class loads or class service characteristics. For example, fixed production capacity costs are typically allocated using a production demand allocator while billing costs are often allocated based on the number of customers in each rate class.

As demonstrated by the diagram above, the allocation of system costs occurs at both the jurisdictional level and the rate class level. If regulators among the different jurisdictions select different allocation methodologies to allocate the utility's costs, the sum of the allocators may not equal 100%, and the utility may not be able to fully recover its costs, or it may recover more than 100% of its costs.

Some state regulatory commissions have addressed this by selecting one allocation method for the jurisdictional allocator to separate the retail jurisdiction from the wholesale jurisdiction – usually one of the preferred FERC methods – and a different allocation method to allocate costs among the retail classes. A few examples of this are:

1. Arizona Public Service Company uses the 4CP method for jurisdictional separation purposes and the Average & Excess method for allocating to rate classes.

2. Duke Energy Florida uses a 12CP demand method for jurisdictional purposes and 12CP demand plus 1/13th average demand for allocating to rate classes.
3. Minnesota Power uses the 12CP demand method for jurisdictional separation purposes and the Peak and Average method for allocating to rate classes.

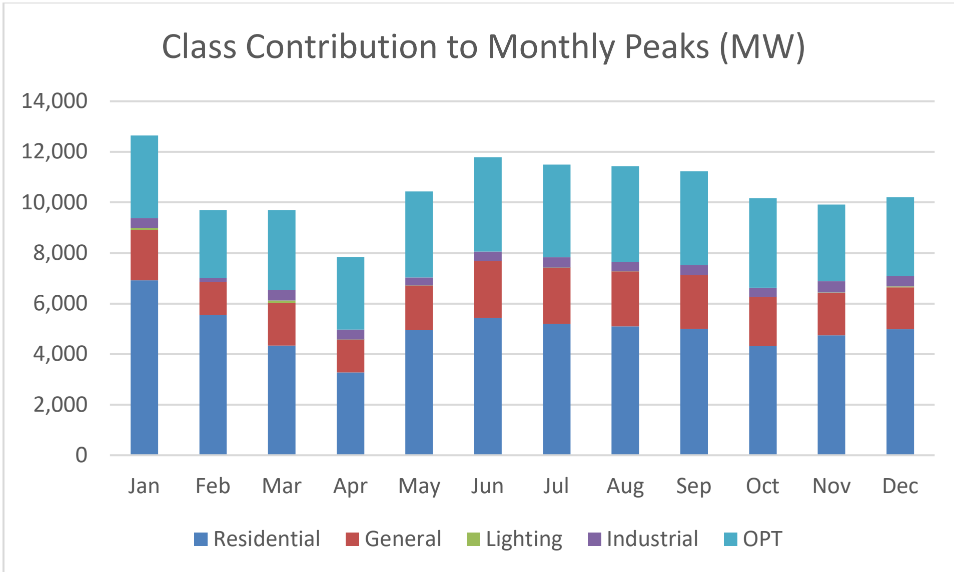
However, North Carolina has maintained consistency between the methodology applicable to the jurisdiction and customer-class levels.

The Production Capacity/Energy Tradeoff

For a vertically integrated electric utility, production-related costs are typically the largest single component of costs it incurs. Since the allocation method chosen can have significant impacts on the costs assigned to the utility's rate classes, it can be a topic of considerable debate among the various participants in a utility rate case.

Electric utilities design and build their generation resources to meet both the demand and energy requirements of their customers on an aggregate basis. Since production facilities are joint costs, they must be allocated to the various customer classes.

Electric utilities experience periods of higher demand during various hours of the day and during certain times of the year. At the same time, the various customer classes do not contribute in the same proportions to these varying demands over time. To demonstrate this phenomenon, the graph below provides Duke Energy Carolinas' twelve monthly peaks for 2018 with each of the major classes' contribution to those peaks.



DEC Exhibit 1 provides the load data which is the basis for the above chart[2]. DEP Exhibit 1 provides the same data for DEP. DEC Exhibit 23 provides the same data as DEC Exhibit 1 for two winter peak months, two summer peak months and two off-peak months. It more clearly shows the weather impacts on the residential class and the more consistent loads of the OPT class.

Utilities are required to have adequate generating resources to meet the system's peak demand plus a reserve margin (i.e., additional generation resources above and beyond the peak demand). At the same time, electric utilities have historically designed their mix of generation facilities and purchased power resources to minimize the total cost of electric service. Base load units, like nuclear, coal and natural gas combined-cycle, have historically required high capital expenditures per kW of capacity but have relatively lower variable production costs per kWh for fuel and operations and maintenance ("O&M") expenses. On the other hand, peaking units have

[2] OPT rates are optional power service time-of-use rates defined by the voltage level needs of the DEC customer.

historically required lower capital costs per kW but relatively higher production costs per kWh. Based on the varying levels of demand incurred by an electric utility system over time, the utility seeks through the integrated resource planning process to determine the optimal mix of production facilities that minimizes the total cost of production.

In addition, many utilities are transforming their generation systems to meet clean energy plans for the generation and resources that serve their customers, through the retirement of coal-fired facilities and the addition of clean renewable resources, including intermittent solar and wind capacity and energy limited resources such as battery storage. Intermittent resources affect system operations since dispatchable resources must be available to ramp up and down to accommodate unexpected movements in solar and wind output.

In this report, this concept of how energy usage influences resource planning and fixed cost resource additions is referred to as the production capacity/energy trade-off. Some production demand allocation methods attempt to capture the impacts of the production capacity/energy trade-off by including energy – or average demand – in the calculation of the production demand allocator. Other methods assume this trade-off is accounted for by allocating variable production costs based on energy allocators and fixed production costs based on peak demand allocators. This concept will be referenced in the review of the strengths and weaknesses of each method.

Production and Transmission Cost Allocation Methods

The National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("CAM"), first published in 1992, serves as a primer on cost allocation methodologies. This manual discusses more than a dozen embedded cost allocation methods. The NARUC manual classifies these methods as:

- Peak responsibility demand methods that reflect the view that capacity is built to meet peak demand requirements and not energy needs.
- Energy weighting methods that reflect the view that generation facilities are built to meet both demand and energy requirements.
- Time differentiated methods – These methods are designed to allocate costs to base and peaking periods and sometimes to an intermediate period. Some of these methods are complex and require significant data to perform the necessary calculations.

This study focuses on the methods agreed to in the Second Partial Stipulations as well as some other commonly used methods requested by the stakeholder group. This section includes a discussion of strengths and weaknesses of the various methods. Charts summarizing the strengths and weaknesses are found in Duke Energy ("DE") Exhibits 1 and 2, respectively.

Single Coincident Peak: One of the most fundamental operating concepts for an electric utility is that it must have sufficient generating capacity to meet the electric system's maximum coincident peak demand for the year. To that end, capacity planners must ensure there is enough generation capacity available to meet that demand plus a prescribed reserve margin. The reserve margin is designed to ensure adequate generation in the event that the weather is more extreme or load is more robust than forecasted or in the event of planned or forced outages of generating units. A major strength of the single coincident peak method is that it generally aligns with the resource planning objective of meeting peak demand and energy requirements throughout the year by delivering affordable, reliable and increasingly cleaner energy to customers.

For DEC and DEP, capital costs were incurred over several decades when the utilities were primarily summer peaking. From a maximum capacity (MW) standpoint, resource planning was based on the summer peak. A Winter CP reflects how resource planning will reflect drivers of costs going forward. Also, single CP methods justify or support rate design structures that encourage reduction of load at the times of system peak and the shifting of usage to off-peak, both of which can eliminate or delay the addition of future generation resources. A final advantage of this method is that it is relatively simple to understand.

Advocates for this method argue that each customer class is responsible for their contribution to this single peak demand and should be allocated its proportional share of the utility's fixed capacity cost. Critics of this method argue that it does not address the capacity/energy tradeoff discussed above. Under this method, all the system's fixed capacity costs are allocated based on each classes' relative contribution to the single peak hour. Or, said another way, it does not consider the fact that customers use the production system during the other 8,759 hours of the year. They further argue that as the utility decides the size and type of generating capacity to build, it must consider not only the maximum coincident peak load but also the utility's customer demands throughout the year. They contend that if the utility only needed to consider the single peak hour, the utility would only install peaking units since they have the lowest installed cost per kW. But peaking units have the highest operating costs per kWh. As a result, as noted above, a utility installs a mix of generation to meet demand and energy needs to optimize total capital and operating costs.

Another argument against this method is that a typical utility's maximum coincident peak is usually driven by weather extremes (heat or cold). Residential customer loads, more than other customer class loads, are impacted significantly by weather due to the significance of heating and cooling loads to the total loads of residential customers. In addition, the actual peak load can vary significantly from forecasted load. This volatility can result in significant changes in rate class cost responsibility from year to year. The result may be large swings in cost allocation to customers, impacting the ability of the utility to maintain stable rates for its customers. The stakeholder group discussed that one potential way to mitigate this issue of volatility is to use forecasted/weather normalized peak demand data when developing the allocation factors. This approach would remove the volatility created by test years with extreme weather at the peak.

Another issue with the single coincident peak method is that some rate classes may not be allocated any production and transmission related fixed costs because they have no load at the time of the peak. For example, the lighting class for DEC/DEP, other than traffic signals, are allocated little, if any, fixed cost under the summer coincident peak method because there is no lighting load at the time of DEC's/DEP's summer peaks.

Four Coincident Peak Method ("4CP"): A 4CP method has some of the same advantages and disadvantages as the single coincident peak method discussed above but takes some of the variation of utility monthly peaks into account. This method has several variations; it may average the four maximum monthly peaks regardless of season, or average the two maximum summer peaks and the two maximum winter peaks to deliberately reflect seasonal differences.

Advocates for this method point out that it can capture the seasonal variation in the utility's loads while at the same time reducing the volatility inherent in the single CP method. Also, FERC commonly accepts multiple CP methods.

Similar to the single coincident peak method, critics of this method believe that looking at four hours of load is not enough to represent the non-peak usage of the generating fleet.

Twelve Coincident Peak Method ("12CP"): This method averages all twelve of the utility's monthly coincident peaks in an attempt to capture the seasonal variation in the loads while also reducing the possibility of a rate class avoiding any peak responsibility. Generally, the more peaks used, the less impact any individual peak has on the allocation of fixed production and transmission costs. The averaging effect of multiple peaks also temper the impact of seasonal differences in peaks and the character of those peaks.

FERC has issued guidance on when the 12CP method may be an appropriate allocation method in proceedings before it. On page 31 of Opinion No. 501 in Docket Nos. EL05-19-002 and ER05-168-001 FERC said:

> A company that has a relatively flat demand curve throughout the year would typically allocate demand on a 12 CP basis, which assumes that a utility's demand is relatively constant throughout all twelve months of the year.

In this same order, FERC proceeded to describe three tests that could be used by FERC to determine whether a utility's load shape qualified it for the 12CP allocation method. Upon a review of these three tests, it is apparent that FERC has constructed these tests to measure the relative "flatness" of the twelve-monthly peaks to each other. DEC Exhibit 2 and DEP Exhibit 2 provide the results of these three tests for their respective utility for the ten years ending with 2018. DEC qualifies for 12CP treatment with tests 1 and 3 in all ten years but only six of ten years for test 2. DEP qualifies for 12CP treatment with test 1 in all ten years but only seven out of ten years for tests 2 and 3.

Advocates for this method point out that it mitigates some of the weaknesses of the single CP method in that it ensures that those rate classes that use the system pay for the system and moderates the impact of weather extremes in any month by equally weighting all twelve monthly peaks.

Critics of the 12CP method contend that utilities do not design their generating systems to meet twelve peaks. Nevertheless, utilities typically have high system peaks in the summer and winter months and lower system peaks during the spring and fall months. If the utility assigns peak responsibility to its rate classes based on their contributions to each monthly peak, then their allocated costs will reflect that the utility called on almost all its generating resources during the highest peak months but only its more efficient generating units during the lower peak periods. In addition, the 12CP method does not encourage load shifting to the same extent as a single CP method.

DEC Exhibit 3 and DEP Exhibit 3 show peak demands for each of the four peak-responsibility methods discussed above.

Summer Winter Peak and Average Method ("SWPA"): The concept behind the SWPA method is that a utility builds generating facilities to not only meet peak demand but also to serve customer energy needs throughout the year. Thus, these methods allocate fixed capacity costs partially based on each classes' contribution to peak demand and partially on the basis of energy consumption throughout the year. While there is no universal approach as to what peak demands should be used or the weighting between the peak and average portions, typical methods use coincident peak demand for the peak component and the system load factor for the weight of the energy portion and one minus the system load factor to weight the peak segment.

Advocates for this method state that this method recognizes the capacity/energy tradeoff in the allocation of fixed capacity costs, which is not present in the various peak responsibility methods described above.

Critics of this method point out that a significant amount of production fixed costs is allocated to the rate classes based on energy consumption but with no offset for the lower fuel costs incurred by the utility during off-peak periods. They contend that this method is detrimental to high load factor customers, who more efficiently utilize the utility's facilities than low load factor customers whose load is more volatile, requiring more capacity to serve their load. High load factor customers consume a more constant amount of energy across the hours of the year including the less expensive off-peak hours. Under this method, a high load factor class will be assigned significant fixed capacity costs while, at the same time, allocated fuel costs based on a system average. If the variation in hourly fuel costs is substantial, high load factor customers will be allocated a disproportionate share of the fuel costs.

Another issue with this method, argued by some customer groups, is the use of average load in the calculation of the peak demand component. If peak demand is defined as average demand plus excess demand (the difference between a class's demand and its corresponding average demand), these groups believe that using a weighted average of peak demand and average demand results in allocation factors that double count average demand. This result occurs because the peak demand segment contains an average load component.

DEC Exhibit 4 and DEP Exhibit 4 provide an example calculation of the SWPA method for each utility.

Average & Excess Method ("A&E"): Another energy weighting method described in the NARUC CAM is the average and excess method. While the A&E method was not a method included in the Second Partial Stipulations, it was included in this study at the request of a stakeholder. The A&E method considers that generation facilities are needed to serve a utility's "average load," as well as its "excess or peak load," in assigning responsibility for the recovery of production fixed costs. The A&E allocation demand factor is composed of two parts. The average demand for the test year is calculated by dividing the test year number of kilowatt-hours at the generator by the number of hours in the test year (for 2018 there were 8,760 hours). The excess portion of the demand factor is the difference between the system average demand and the system peak demand. It is important to note that the NARUC CAM defines the excess demand for this method as the difference between non-coincident demand (the sum of the individual maximum demands regardless of time of occurrence within the specified period) and average demand[3]. The average demand component of the A&E allocation factor is each class's average demand times the system load factor. This measures the amount of demand incurred if the utility served this amount of load at a constant 100% load factor. The excess demand component of the A&E factor measures the variability of each class's load. The greater a class's load variability, the greater the amount of load-following resources needed to provide the total load requirement. This excess portion is multiplied by one minus the load factor. Lastly, the sum of these two demands by class or jurisdiction are divided by the system total to produce each class or jurisdiction's Average & Excess allocator.

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[3] The NARUC CAM also points out that the use of non-coincident peaks with the Average & Excess method avoids the potential of a negative allocator caused by a rate class with a zero CP. For example, using Summer CPs, the lighting class could produce negative excess demand.

Like the SWPA method, this method recognizes the capacity/energy tradeoff in the allocation of fixed capacity costs and ensures that all classes are allocated some portion of fixed production costs. Unlike the SWPA method, the A&E method avoids the double counting of demand as excess demand is defined as peak demand less average demand.

Critics of this method note that coincident demands, and not non-coincident demands, are a parameter of interest to system planners. The use of non-coincident demands will, in general, shift production fixed costs to lower load factor customer classes. Like all energy methods, it does not provide for a fuel offset to reflect lower variable fuel costs during off-peak periods to assist high load factor classes that are allocated a larger proportion of fixed costs under average methods.

DEC Exhibit 5 and DEP Exhibit 5 provide an example calculation of the A&E method for each utility.

Average & Excess 4CP Method ("A&E 4CP"): The Average & Excess 4CP method is constructed in the same manner as the Average & Excess Method described above except that 4CP demands are substituted for the non-coincident demands used in the standard A&E method.

Advocates for this method believe that it has some of the same advantages as the peak responsibility methods, like encouraging off-peak usage, while including an energy component to capture off-peak usage.

DEC Exhibit 6 provides an example calculation of the Average & Excess 4CP method for DEC, and DEP Exhibit 6 provides the same example calculation for DEP.

Average & Excess Dominion Method ("A&E DOM"): The Average & Excess Dominion method is not a method mentioned in the NARUC CAM but rather a negotiated, customized variant used by Dominion for its Virginia retail customers that the stakeholder group requested be included in the study. As implemented by Dominion, it uses diversified non-coincident demands instead of non-diversified, non-coincident demands as utilized in the A&E method described above. Use of diversified demands recognize that each customer's maximum load does not occur at the same time. Thus, diversified non-coincident demands represent the class's maximum demand during the period and are invariably less than the non-diversified, non-coincident demands for the same rate class. (For example, the maximum demand for one class may be at 5 PM while the maximum demand for another class may be at 2 PM.) Average demand and excess demand are calculated in the same manner as the two previously described A&E methods. This method adds an additional step of scaling down the excess demands for each rate class such that the average plus excess demands equal the summer coincident demands at a system level for each utility. The result of all these calculations is that the interrelationships between the classes matches their non-coincident demands but the total excess demand equals the system excess based on the summer coincident demand. These resulting class excess demands are then added to their respective average demands to determine the total average & excess demands under this method.

In general, this method has the same strengths and weaknesses as the A&E method described above. Additionally, the extra steps outlined above make its calculations a little more difficult to understand than the standard A&E method.

DEC Exhibit 7 provides an example calculation of the A&E DOM method for DEC, and DEP Exhibit 7 provides the same example calculation for DEP.

Base, Intermediate and Peak Method ("BIP"): The NARUC CAM classifies this method as a time-differentiated method. This method classifies each generating resource as base, intermediate or peaking based on its role within a utility's portfolio of generation facilities and, likewise, assigns each unit's plant investment to each category of generating plant. In this manner, a weighting of high fixed cost base load units relative to lower fixed cost peaking units is achieved.

Advocates of this method contend that it recognizes that generating facilities are added to meet the varying needs of the system. High fixed cost, low variable cost base load units with high capacity factors run continuously throughout the year to meet the energy needs of all customers. Thus, base load units, under this method, are allocated based on energy. In contrast, low fixed cost, high variable cost peaking units are built to run only a few hours per year during high peak demand periods and, therefore, have relatively low capacity factors. These peaking units are typically allocated based on a peak demand method like 1CP or 4CP. Both DEC and DEP allocated these peaking unit costs at the summer single coincident peak demand allocation method in this study as presented in DEC Exhibit 8 and DEP Exhibit 8.

In between the base load units and the peaking units are the intermediate generating resources. While these units may not be dispatched during periods of low system load, these relatively efficient units do operate for many hours of the year. Under this method, the plant investment in these units is typically allocated to the energy classification based on their annual capacity factors with the remainder allocated to capacity.

Hydro units are addressed on a case-by-case basis. Pumped storage units by design are intended to provide peaking power although in actual practice they may be used at other times as well. A case can be made to assign these units 100% to demand. Since reservoir or storage hydro units can be subject to daily or seasonal restrictions on water releases, assignments could be based 50% energy and 50% demand. Run-of-river hydro units are typically assigned to the energy component based on their annual capacity factors. In this study, solar units were assigned to the energy component based on the overall annual solar capacity factor.

Example calculations of this method can be found in DEC Exhibit 8 and DEP Exhibit 8.

Assigning the plant investment costs of each generator to their respective energy or demand classification does not result in values that immediately translate into allocation factors that are useable in the DEC and DEP cost of service allocation models. Thus, it was necessary to allocate each generation type's energy and demand investment costs to the rate classes using the appropriate allocator and then sum the resulting values by rate class to calculate a composite BIP allocator. The development of these allocators can be found in DEC Exhibit 9 and DEP Exhibit 9. Please note that the Exhibit 9s represent an attempt by each utility to create traditional class allocation factors based on the calculation of the BIP method.

Advocates for this method state that it recognizes the mix of a utility's resources used to serve its varying demands throughout the year and that it permits the weighting of expensive base load plants versus less expensive peak load units. Lastly, it recognizes the capacity/energy tradeoff.

Critics argue that a major weakness in the BIP method is that it allocates 100% of base production fixed costs using an energy allocator. Said another way, it fails to consider that baseload units are not simply operated for purposes of providing energy, but also contribute towards meeting peak demand. Critics further state that given that base units, by definition, have high capacity factors, it seems illogical not to assign some proportion of their fixed costs with a demand factor. Critics also say another major weakness of the BIP method, like all the methods using energy to allocate capacity fixed costs, is that no offset is made to reflect lower variable fuel costs during off-peak periods. Another drawback to this method is the lack of consensus among industry experts on which demands (1CP, 4CP, 12CP, etc.) to apply to the intermediate and peak categories. Finally, this approach may distort the relative values of the base, intermediate and peaking components due to the timing of each component member's plant installation dates.

CIGFUR Exhibit 1 provides specific comments on the BIP method by the Carolina Industrial Group for Fair Utility Rates.

Summary of Production Demand Allocation Methods

The table below summarizes the 2018 DEC production demand allocators by rate class for each of the nine allocation methods described herein:

Duke Energy Carolinas, Inc.

DEC Exhibit 10

Cost of Service Analysis Results
Production Demand Allocation Factors
For the twelve months ending December 2018

		Peak Responsibility Methods				Energy Weighting Methods				Time Differentiated Method
	Load Factor	Summer 1 CP	Winter 1 CP	4CP	12CP	SWPA	A&E	A&E 4CP	A&E Dom	BIP
		Exhibit3	Exhibit3	Exhibit3	Exhibit3	Exhibit4	Exhibit5	Exhibit6	Exhibit7	Exhibit8
North Carolina:										
Residential	50.11%	30.9900%	36.6484%	32.5594%	31.4863%	29.6899%	38.8639%	30.5591%	31.1211%	27.0273%
SGS	46.63%	6.7074%	5.2708%	5.8334%	5.5219%	5.5322%	5.8993%	5.6279%	5.6949%	5.3972%
LGS	56.23%	6.2578%	5.3386%	5.9541%	6.1287%	5.7486%	4.9931%	5.8888%	5.6962%	5.8592%
Lighting		0.0073%	0.4168%	0.1764%	0.1332%	0.4874%	0.6955%	0.3381%	1.0029%	0.5587%
Industrial	66.93%	2.0918%	2.0516%	2.2797%	2.3447%	2.1698%	2.3050%	2.2781%	2.7276%	2.2557%
OPT-Small	67.49%	8.2635%	7.0243%	7.6300%	7.7505%	8.3204%	6.0084%	8.0195%	7.2305%	8.7455%
OPT-Medium	78.04%	2.7678%	2.3229%	2.6391%	2.7923%	3.0099%	2.1277%	2.8762%	2.6956%	3.2896%
OPT-Large	83.72%	9.5019%	7.2610%	8.8122%	9.5791%	10.5692%	7.2286%	9.9324%	9.2848%	11.9047%
OPT-Trans	97.01%	0.8471%	0.6880%	0.8322%	0.9322%	1.0421%	0.6813%	0.9692%	0.8887%	1.2005%
NC Retail		67.4345%	67.0222%	66.7165%	66.6688%	66.5694%	68.8029%	66.4893%	66.3423%	66.2385%
NC Wholesale	78.09%	4.1506%	5.8272%	4.9532%	4.8449%	5.1394%	4.0024%	5.0381%	5.7230%	5.0301%
Total NC	61.19%	71.5851%	72.8494%	71.6698%	71.5137%	71.7088%	72.8052%	71.5274%	72.0652%	71.2687%
South Carolina:										
Residential	49.01%	9.6153%	10.8916%	10.1920%	10.0098%	9.0002%	12.3610%	9.4998%	9.4302%	8.2998%
SGS	48.60%	1.9186%	1.4200%	1.6870%	1.6619%	1.5890%	1.7157%	1.6399%	1.6762%	1.5988%
LGS	54.22%	1.4567%	1.2166%	1.3819%	1.3633%	1.3081%	1.2142%	1.3549%	1.4368%	1.3215%
Lighting		0.0016%	0.1312%	0.0562%	0.0420%	0.1566%	0.2208%	0.1088%	0.3242%	0.1806%
Industrial	60.75%	0.8638%	0.7101%	0.8518%	0.8673%	0.8173%	0.7531%	0.8520%	0.9073%	0.8563%
OPT-G	69.26%	3.0100%	2.5992%	2.7900%	2.8590%	3.0837%	2.2284%	2.9526%	2.6195%	3.2513%
OPT-I	88.21%	6.4648%	5.0703%	6.3133%	6.7756%	7.4552%	5.2306%	7.1174%	6.5993%	8.4667%
SC Retail		23.3309%	22.0390%	23.2723%	23.5790%	23.4101%	23.7237%	23.5254%	22.9934%	23.9750%
Greenwood	52.13%	0.0660%	0.0687%	0.0685%	0.0688%	0.0618%	0.0966%	0.0650%	4.8046%	0.0593%
SC Wholesale	56.40%	5.0180%	5.0428%	4.9895%	4.8385%	4.8193%	3.3744%	4.8823%	0.1368%	4.6970%
Total SC	62.52%	28.4149%	27.1506%	28.3302%	28.4863%	28.2912%	27.1948%	28.4726%	27.9348%	28.7313%
System		100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

The table below summarizes the 2018 DEP production demand allocators by rate class for each of the nine allocation methods described above:

Duke Energy Progress, LLC

DEP Exhibit 10

Cost of Service Analysis Results
Production Demand Allocation Factors
For the twelve months ending December 2018

		Peak Responsibility Methods				Energy Weighting Methods				Time Differentiated Method
	Load Factor	Summer 1 CP Exhibit3	Winter 1 CP Exhibit3	4CP Exhibit3	12CP Exhibit3	SWPA Exhibit4	A&E Exhibit5	A&E 4CP Exhibit6	A&E Dom Exhibit7	BIP Exhibit8
North Carolina:										
Residential	51.63%	30.5172%	38.3159%	33.2051%	32.2792%	30.0550%	41.7009%	31.7100%	27.8609%	27.7355%
SGS	49.49%	3.7875%	3.5686%	3.6127%	3.6016%	3.3859%	3.9997%	3.5090%	3.1883%	3.2581%
MGS	60.85%	17.3390%	12.0421%	15.6483%	16.3051%	16.3220%	13.7520%	16.0965%	16.3072%	17.3977%
Industrial	92.93%	0.0436%	0.0241%	0.0554%	0.0662%	0.0524%	0.3771%	0.0581%	0.2613%	0.0666%
LGS	80.28%	9.8361%	5.6365%	8.4253%	9.3489%	10.7321%	6.5313%	9.4837%	9.4051%	12.3316%
Lighting		0.0045%	0.0045%	0.0046%	0.0049%	0.3117%	0.4407%	0.1287%	0.6374%	0.4347%
NC Retail	59.25%	61.5278%	59.5918%	60.9514%	61.6058%	60.8591%	66.8018%	60.9861%	57.6602%	61.2242%
NC Wholesale	58.96%	28.6661%	31.5845%	29.4869%	28.5332%	29.1464%	22.6109%	29.2320%	32.4976%	28.3821%
Total NC	59.16%	90.1939%	91.1763%	90.4383%	90.1390%	90.0056%	89.4127%	90.2181%	90.1578%	89.6063%
South Carolina:										
Residential	52.20%	3.9667%	5.1778%	4.3745%	4.2060%	3.9720%	5.6226%	4.1756%	3.6040%	3.6358%
SGS	48.07%	0.5573%	0.5127%	0.5559%	0.5432%	0.4882%	0.6619%	0.5324%	0.5699%	0.4719%
MGS	61.60%	2.5321%	1.8243%	2.2811%	2.3852%	2.4158%	2.0602%	2.3544%	2.4248%	2.5656%
Industrial	72.36%	0.0240%	0.0277%	0.0264%	0.0247%	0.0276%	0.0875%	0.0270%	0.0544%	0.0281%
LGS	89.84%	2.3649%	0.9578%	1.9834%	2.3735%	2.6962%	1.8390%	2.3305%	2.7211%	3.2787%
Lighting		0.0008%	0.0008%	0.0008%	0.0009%	0.0701%	0.0961%	0.0288%	0.1405%	0.0978%
SC Retail	64.75%	9.4459%	8.5010%	9.2222%	9.5335%	9.6699%	10.3673%	9.4487%	9.5147%	10.0780%
SC Wholesale	51.41%	0.3602%	0.3227%	0.3395%	0.3275%	0.3245%	0.2200%	0.3331%	0.3275%	0.3157%
Total SC	64.26%	9.8061%	8.8237%	9.5617%	9.8610%	9.9944%	10.5873%	9.7819%	9.8422%	10.3937%
System		100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

The Duke Energy Cost of Service System

The financial inputs into the cost of service study are based on the official accounting books and records of Duke Energy Carolinas ("DEC") and Duke Energy Progress (DEP) using the FERC Uniform System of Accounts.

The Duke Energy cost of service study is an internally developed Microsoft Excel-based model that established the cost to serve each class, and functionalizes those costs across production, transmission, distribution and customer functions. These functionalized costs are grouped into demand, energy and customer classifications based on cost causation. Supporting files for the cost of service study include the financial inputs mentioned earlier as well as the input allocation factors for each customer class based on each class's contribution to peak demands (KW), annual consumption of energy (kWh), number of customers, etc. The final workbook in this system develops derived allocation factors[4], which it uses along with the input allocation factors to allocate or directly assign the costs described above to the appropriate jurisdiction and customer class based on cost causation. The result of the cost of service study is the assignment or spread of revenues, expenses, and rate base components to the jurisdictions and customer classes served by the electric utility. The cost of service study can be prepared in different versions in a rate case, ranging from a per books cost of service to a proforma adjusted cost of service at present or proposed rates. It can also be prepared using different allocation methods such as the Single Summer Coincident Peak or the SWP&A.

[4] Derived allocation factors are calculated by summing by class specifically defined values that have been allocated using input allocation factors and dividing by the sum of all the classes.

Once the allocation process is complete, the operating income for return is derived for each jurisdiction and rate class by subtracting the allocated operating expenses and interest on customer deposits from the revenues. Next, the rate of return on rate base is determined by dividing the income for return by the allocated rate base for each rate class. Once the rate of return by rate schedule is known, the unit cost calculation provides for a functionalized view of each rate class's revenue requirement such that each function earns the same rate of return within that class. These unit costs are a guide or starting point in the rate design process. DEC Exhibits 15 through 23 provide the unit costs for each of the nine DEC allocation methods described in this report. DEP unit cost reports can be found in DEP Exhibits 15 through 22.

As mentioned earlier, one of the most important parameters calculated in a cost of service study is return on rate base as it provides an indication of how much of a rate increase/decrease each rate class must experience so that each rate class earns the same overall return. DEC Exhibit 11 and DEP Exhibit 11 provide the rate of return under present rates for each rate class of the respective utilities. DEC Exhibit 12 and DEP Exhibit 12 provide each rate classes' rate of return index with respect to its jurisdiction's overall rate of return. An index value of less than one indicates that the rate class's return is less than the jurisdictional return and likely needs a revenue increase to match that jurisdictional return.

Allocation of Fuel Costs

Fuel costs are considered "pass-through" costs as they are passed on to customers on a dollar-for-dollar basis, and do not include a return component. The rate tariffs for both DEC and DEP include a base fuel component and a separate fuel adjustment clause charge. A fuel adjustment clause is a regulatory provision that permits a change in rates to occur because of a change in the cost of fuel or the variable portion of purchased power expenses. These changes occur without the utility filing a formal rate case. Rather, in North Carolina and South Carolina, the regulatory commissions conduct annual fuel adjustment proceedings to adjust the fuel adjustment charge up or down as appropriate. These smaller focused proceedings are designed to eliminate the lag between changes in fuel costs and the reflection of these changes in rates. Thus, a fuel adjustment clause acts as an interim measure for adjusting rates to reflect changes in a large and highly volatile expense item so that under-recovery or over-recovery of the expense does not lead to financial deterioration or excess profits for the utility.

The base fuel component (approved in a general rate proceeding) plus the prospective adjustment to the base fuel component (approved in each annual fuel proceeding) (in total, the prospective fuel rate) is set to collect from customers the estimated prospective cost of fuel and purchased power energy costs. The deferred fuel rate (experience modification factor, or EMF) is designed to eliminate the difference between the prospective fuel rate revenues and the utility's actual costs of fuel and purchased power, so that in the end customers only reimburse the utility for its actual costs. If the prospective fuel rate is higher than actual costs, customers receive a credit in the deferred fuel account. If the prospective rate is lower than actual costs, the utility collects the difference. Both rates (prospective rate and EMF) are updated each year in the utility's fuel proceeding.

Since both electric utilities have fuel adjustment clauses which are separately reviewed and approved by the regulatory commissions, the fuel expense captured in a cost of service study is only that portion related to the base fuel component in rates plus the deferred fuel expense for the test year. Said another way, the base fuel expense plus deferred fuel expense for any rate class is exactly offset by that same rate class's fuel revenues. Since these revenues and expenses cancel each other, fuel has no bearing on the final results of the cost of service study.

One criticism of fixed cost allocation methods using average energy is that high load factor customers will be assigned more fixed capacity costs while, at the same time, allocated fuel costs based on an average. (In North Carolina, the average rate is modified to produce an equal percent increase across all rate classes). High-load factor customers consume a more constant amount of energy across the hours of the year including the less expensive off-peak hours. If the variation in hourly fuel costs is substantial, high load factor customers will be allocated a disproportionate share of those fuel costs.

DEC Exhibit 13 and DEP Exhibit 13 provide one of many possible approaches that could be used to ensure that those rate classes that cause the system to incur more fuel costs are then allocated proportionately more of the higher-priced fuel. Each generator that uses fuel was classified as base, intermediate or peaking and their fuel costs were included in their respective BIP total. Each rate classes' average demand, 12CP demand and SCP demand (columns 3, 6 & 9) were used to develop allocators as a percent of the total system (columns 5, 8 & 11). In turn, these allocators were applied to the total annual base, intermediate and peaking fuel costs to determine each classes' allocated share of these three fuel classifications. These three fuel costs are then added to produce the rate classes' allocated share of fuel expense for the test year.

As shown in column 19 on page 2 of DEC Exhibit 13, under this conceptual approach, the NC Residential class and the SC Residential class are allocated almost $65 million more in fuel costs than under a system average method. In contrast, the high-load factor NC OPT Large rate class is allocated $26 million less in fuel costs.

For only those methods that employ average energy to allocate production fixed costs, DEC Exhibit 14 and DEP Exhibit 14 provide each rate classes' rate of return on rate base after the application of these incremental fuel costs to each rate classes' expenses[5].

Conclusions

Based on the Second Partial Stipulations between Duke Energy and the Public Staff, Duke Energy formed a stakeholder group to engage in an investigation of nine different production demand allocation methods. Industry accepted approaches for each method used in the study were determined and the strengths and weaknesses of each method were documented. Next, the resulting allocation factors for each method were used in each utility's cost of service tool to calculate each jurisdiction/rate class's rate of return on rate base. Lastly, a calculation method was developed to examine whether certain rate classes might be assigned more or less fuel costs than under a simple average fuel rate method.

Unfortunately, this effort to evaluate nine different methods did not result in a single method that all involved stakeholders would support. It will be up to each interested party to propose and support its preferred methodology and for the regulatory commissions to make a finding based on the facts and evidence presented in each rate case. Nonetheless, many members of the study group agreed that their knowledge and understanding of these allocation methods was increased by their participation in this process.

[5] In a typical year, fuel revenues and fuel expenses should offset with no impact on ROR. For illustrative purposes, however, Exhibit 14 demonstrates the impact of modifying fuel expense allocations (and revenues) in the 2018 test year to address some of the issues around the energy weighting allocation methods and indicate how each rate class might be affected.

Lastly, the participants in this study hope the North Carolina Utilities Commission, the South Carolina Public Service Commission, the North Carolina Public Staff, the South Carolina Office of Regulatory Staff and other interested parties find this final report both helpful and informative.

Definition of Terms

Coincident Peak or CP – a customer's or customer classes' demand at the moment in time that the total system experiences its maximum peak load.

Non-Coincident Peak or NCP – a customer's or customer classes' maximum demand irrespective of when it occurs.

Demand - the amount of energy consumed at a single point in time. Expressed in either KW, MW or GW.

Average Demand –the total kWh of energy consumed in the period divided by the total number of hours in the period. If a customer consumes 876,000 kWh during a year, the customer's average demand is then 100KW. This calculation is analogous to the average speed of an automobile on a trip.

KW – Kilowatt or 1000 watts which is a measure of power. A KW represents how much power is needed at an instant in time.

MW – Megawatt or 1,000,000 watts.

KWH –a measure of energy. A 100-watt light bulb burning 10 hours will consume 1,000 watt-hours or 1 kWh. It measures how much energy is used in one hour.

KV - Kilovolt – A volt is the difference of potential that would drive one ampere of current against one ohm of resistance between two points on a conducting wire. A kilovolt is 1,000 volts.

KVA – Kilovolt-ampere - A volt-ampere (VA) is the voltage times the current feeding an electrical load. A kilovolt-ampere (**kVA**) is 1000 volt-amperes.

Load Factor (kWh consumed in period)/ (KW peak x hours in period) – a measure that captures the degree of variation in the pattern of demand. The closer the load factor is to 1, the less variation in the pattern of demand. The closer the load factor is to zero, the more the variation in the pattern of demand. A high system load factor translates into a higher utilization of the generating system and into a lower average cost per kWh. A higher load factor customer requires less capacity for the same amount of energy as demonstrated by this simple example:

30% Annual Load Factor = 100,000kWh / (38.05KW x 8760 hours)

60% Annual Load Factor = 100,000kWh / (19.025KW x 8760 hours)

Thus, a low load factor customer requires more capacity to be built to serve their load than a high load factor customer; however, a high load factor customer requires more baseload (higher capital cost) capacity to be built than a low load factor customer.

Load Curve – the pattern of instantaneous demand through a defined period. A monthly load curve looks at 730 hours while an annual load curve examines 8760 hours.

Duke Energy Carolinas

DEC Exhibit 1

Production Demands

Year: 2018

	Coincident Peaks											
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
North Carolina:												
Residential	6,917,677	5,539,660	4,344,394	3,276,672	4,944,475	5,420,002	5,204,310	5,096,485	4,996,228	4,315,875	4,744,968	4,979,116
SGS	994,904	598,217	727,931	507,600	865,296	1,173,097	1,124,484	1,056,617	1,047,055	947,796	698,474	742,457
LGS	1,007,695	704,430	948,385	790,920	909,849	1,094,460	1,097,280	1,120,252	1,072,929	998,580	972,143	918,945
Lighting	78,669	1,609	95,192	1,161	1,117	1,270	1,190	1,151	1,330	1,085	28,258	40,885
Industrial	387,247	172,857	425,886	393,083	310,135	365,855	404,088	375,869	402,920	361,622	432,369	419,636
OPT-Small	1,325,901	950,939	1,177,102	990,661	1,239,465	1,445,244	1,391,153	1,368,461	1,347,734	1,283,613	1,079,412	1,115,340
OPT-Medium	438,459	331,189	442,154	382,657	445,958	484,083	482,442	509,055	484,294	450,848	429,733	420,496
OPT-Large	1,370,565	1,273,450	1,403,547	1,365,432	1,568,791	1,661,833	1,644,906	1,744,159	1,716,897	1,644,612	1,374,660	1,418,051
OPT-Trans	129,864	133,755	135,412	136,065	148,822	148,149	144,905	164,262	163,789	161,124	151,072	152,697
NC Retail	12,650,981	9,706,106	9,700,003	7,844,251	10,433,908	11,793,993	11,494,758	11,436,311	11,233,176	10,165,155	9,911,089	10,207,623
NC Wholesale	1,099,929	858,892	745,336	671,533	651,301	725,919	732,710	704,329	689,597	588,581	862,931	867,561
Total NC	13,750,910	10,564,998	10,445,339	8,515,784	11,085,209	12,519,912	12,227,468	12,140,640	11,922,773	10,753,736	10,774,020	11,075,184
South Carolina:												
Residential	2,055,870	1,608,802	1,344,568	1,292,230	1,543,104	1,681,673	1,667,212	1,665,234	1,399,069	1,469,744	1,632,180	1,644,981
SGS	268,044	188,632	182,798	161,281	253,879	335,555	353,517	353,049	322,217	313,492	213,093	209,767
LGS	229,652	129,532	193,725	176,566	192,881	254,778	247,683	251,243	241,317	224,448	222,695	223,767
Lighting	24,774	286	30,245	277	266	280	284	268	308	257	8,985	13,522
Industrial	134,030	61,609	158,247	145,254	123,802	151,075	156,262	151,666	146,097	137,901	132,895	147,848
OPT-G	490,613	344,840	415,846	358,715	456,654	526,432	512,616	523,287	488,935	503,093	406,999	400,162
OPT-I	957,062	871,188	1,039,461	934,757	1,132,868	1,130,670	1,179,448	1,178,427	1,205,087	1,129,341	1,006,177	1,099,713
SC Retail	4,160,045	3,204,889	3,364,890	3,069,080	3,703,454	4,080,463	4,117,022	4,123,174	3,803,030	3,778,276	3,623,024	3,739,760
SC Wholesale	951,870	678,846	649,363	553,015	765,538	877,626	866,904	837,027	781,045	736,314	734,088	754,780
Greenwood	12,974	11,005	9,107	7,669	10,638	11,544	12,220	12,515	10,794	11,569	9,887	10,617
Total SC	5,124,889	3,894,740	4,023,360	3,629,764	4,479,630	4,969,633	4,996,146	4,972,716	4,594,869	4,526,159	4,366,999	4,505,157
System	18,875,799	14,459,738	14,468,698	12,145,548	15,564,838	17,489,545	17,223,614	17,113,356	16,517,641	15,279,895	15,141,019	15,580,340

Duke Energy Carolinas, LLC

DEC Exhibit 2

Cost of Service Analysis Results
FERC 12CP Test
For the twelve months ending December 2018

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Test Results
Annual Maximum:		16,246	16,715	16,985	16,973	15,866	18,253	18,490	18,022	17,422	18,935	
	Month	Aug	Aug	Jul	Jul	Jul	Jan	Feb	Jul	Aug	Jan	
	Month #	8	8	7	7	7	1	2	7	8	1	
Annual Minimum:		10,626	11,224	11,243	11,426	11,799	11,597	11,591	12,921	12,661	12,230	
	Month	Nov	Oct	Oct	Oct	Apr	Apr	Oct	Nov	Apr	Apr	
	Month #	11	10	10	10	4	4	10	11	4	4	
Summer Max:		16,246	16,715	16,985	16,973	15,866	16,480	17,353	18,022	17,422	17,632	
	Month	Aug	Aug	Jul	Jul	Jul	Jul	Jun	Jul	Aug	Jun	
	Month #	8	8	7	7	7	7	6	7	8	6	
Winter Max:		15,869	16,454	15,822	15,391	14,681	18,253	18,490	17,053	16,743	18,935	
	Month	Feb	Dec	Jan	Jan	Feb	Jan	Feb	Jan	Jan	Jan	
	Month #	2	12	1	1	2	1	2	1	1	1	
Test 1: ON and Off Peak Test												
Summer CP Method:												
	Summer Max	16,246	16,715	16,985	16,973	15,866	16,480	17,353	18,022	17,422	17,632	
	Annual Max	16,246	16,715	16,985	16,973	15,866	18,253	18,490	18,022	17,422	18,935	
		100.0%	100.0%	100.0%	100.0%	100.0%	90.3%	93.9%	100.0%	100.0%	93.1%	
	Avg Off-Peak	13,581	14,356	14,259	13,986	14,173	15,014	15,107	15,059	15,096	15,771	
	Annual Max	16,246	16,715	16,985	16,973	15,866	18,253	18,490	18,022	17,422	18,935	
		83.6%	85.9%	83.9%	82.4%	89.3%	82.3%	81.7%	83.6%	86.6%	83.3%	
	Difference	16.4%	14.1%	16.1%	17.6%	10.7%	8.0%	12.1%	16.4%	13.4%	9.8%	
	<= 19%	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	
	Supports 12CP?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**10 of 10**
Test 2: Low to Annual Peak Test												
	Annual Min	10,626	11,224	11,243	11,426	11,799	11,597	11,591	12,921	12,661	12,230	
	Annual Max	16,246	16,715	16,985	16,973	15,866	18,253	18,490	18,022	17,422	18,935	
		65.4%	67.1%	66.2%	67.3%	74.4%	63.5%	62.7%	71.7%	72.7%	64.6%	
	>= 66%	No	Yes	Yes	Yes	Yes	No	No	Yes	Yes	No	
	Supports 12CP?	**No**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**No**	**Yes**	**Yes**	**No**	**6 of 10**
Test 3: Average to Annual Peak Test												
	12CP Average	13,803	14,552	14,486	14,235	14,314	15,136	15,294	15,306	15,290	15,926	
	Annual Max	16,246	16,715	16,985	16,973	15,866	18,253	18,490	18,022	17,422	18,935	
		85.0%	87.1%	85.3%	83.9%	90.2%	82.9%	82.7%	84.9%	87.8%	84.1%	
	>= 81%	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	
	Supports 12CP?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**10 of 10**

From FERC Opinion 501 - Docket Nos. EL05-19-002 and ER05-168-001 - Golden Spread EMC - April 2008

Duke Energy Carolinas

DEC Exhibit 3

Peak Responsibility Methods

Year: 2018

	June Summer 1CP-Sum	January Winter 1CP-Win	January December June July 4CP	12CP
North Carolina:				
Residential	5,420,002	6,917,677	5,630,276	4,981,655
SGS	1,173,097	994,904	1,008,736	873,661
LGS	1,094,460	1,007,695	1,029,595	969,656
Lighting	1,270	78,669	30,504	21,076
Industrial	365,855	387,247	394,207	370,964
OPT-Small	1,445,244	1,325,901	1,319,410	1,226,252
OPT-Medium	484,083	438,459	456,370	441,781
OPT-Large	1,661,833	1,370,565	1,523,839	1,515,575
OPT-Trans	148,149	129,864	143,904	147,493
NC Retail	11,793,993	12,650,981	11,536,839	10,548,113
NC Wholesale	725,919	1,099,929	856,530	766,552
Total NC	12,519,912	13,750,910	12,393,368	11,314,664
South Carolina:				
Residential	1,681,673	2,055,870	1,762,434	1,583,722
SGS	335,555	268,044	291,721	262,944
LGS	254,778	229,652	238,970	215,691
Lighting	280	24,774	9,715	6,646
Industrial	151,075	134,030	147,304	137,224
OPT-G	526,432	490,613	482,456	452,349
OPT-I	1,130,670	957,062	1,091,723	1,072,017
SC Retail	4,080,463	4,160,045	4,024,323	3,730,592
SC Wholesale	877,626	951,870	862,795	765,535
Greenwood	11,544	12,974	11,839	10,878
Total SC	4,969,633	5,124,889	4,898,956	4,507,005
System	17,489,545	18,875,799	17,292,325	15,821,669

Duke Energy Carolinas

DEC Exhibit 4

Summer/Winter Peak & Average Allocation Method

Year: 2018

	Inputs			Calculation						
	Summer Coin. Peak June	Winter Coin. Peak January	MWH @ Gen	Energy Portion of Demand	Energy Allocator	Average Sum/Win Peak	Demand Portion of Demand	Demand Allocator	Peak & Average Demand	Class Allocator
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
North Carolina:										
Residential	5,420,002	6,917,677	23,793,860	1,672,350	25.22%	6,168,840	2,370,708	33.93%	4,043,059	29.69%
SGS	1,173,097	994,904	4,791,551	336,774	5.08%	1,084,001	416,585	5.96%	753,359	5.53%
LGS	1,094,460	1,007,695	5,390,752	378,889	5.71%	1,051,078	403,933	5.78%	782,822	5.75%
Lighting	1,270	78,669	725,804	51,013	0.77%	39,970	15,360	0.22%	66,374	0.49%
Industrial	365,855	387,247	2,144,966	150,759	2.27%	376,551	144,710	2.07%	295,469	2.17%
OPT-Small	1,445,244	1,325,901	8,544,626	600,559	9.06%	1,385,573	532,481	7.62%	1,133,039	8.32%
OPT-Medium	484,083	438,459	3,309,507	232,609	3.51%	461,271	177,268	2.54%	409,877	3.01%
OPT-Large	1,661,833	1,370,565	12,187,525	856,600	12.92%	1,516,199	582,681	8.34%	1,439,281	10.57%
OPT-Trans	148,149	129,864	1,258,942	88,485	1.33%	139,007	53,421	0.76%	141,905	1.04%
NC Retail	11,793,993	12,650,981	62,147,533	4,368,037	65.88%	12,222,487	4,697,148	67.22%	9,065,185	66.57%
NC Wholesale	725,919	1,099,929	4,965,845	349,024	5.26%	912,924	350,840	5.02%	699,864	5.14%
Total NC	12,519,912	13,750,910	67,113,378	4,717,061	71.15%	13,135,411	5,047,988	72.24%	9,765,049	71.71%
South Carolina:										
Residential	1,681,673	2,055,870	7,219,706	507,437	7.65%	1,868,772	718,176	10.28%	1,225,613	9.00%
SGS	335,555	268,044	1,428,590	100,408	1.51%	301,800	115,983	1.66%	216,391	1.59%
LGS	254,778	229,652	1,210,028	85,047	1.28%	242,215	93,084	1.33%	178,131	1.31%
Lighting	280	24,774	234,925	16,512	0.25%	12,527	4,814	0.07%	21,326	0.16%
Industrial	151,075	134,030	804,037	56,512	0.85%	142,553	54,783	0.78%	111,295	0.82%
OPT-G	526,432	490,613	3,194,096	224,497	3.39%	508,523	195,427	2.80%	419,924	3.08%
OPT-I	1,130,670	957,062	8,736,687	614,058	9.26%	1,043,866	401,162	5.74%	1,015,219	7.46%
SC Retail	4,080,463	4,160,045	22,828,069	1,604,470	24.20%	4,120,254	1,583,429	22.66%	3,187,899	23.41%
SC Wholesale	877,626	951,870	4,335,679	304,733	4.60%	914,748	351,541	5.03%	656,274	4.82%
Greenwood	11,544	12,974	52,719	3,705	0.06%	12,259	4,711	0.07%	8,417	0.06%
Total SC	4,969,633	5,124,889	27,216,467	1,912,908	28.85%	5,047,261	1,939,681	27.76%	3,852,590	28.29%
SYSTEM	17,489,545	18,875,799	94,329,844	6,629,969	100.00%	18,182,672	6,987,669	100.00%	13,617,638	100.00%

Hours in Year: 8,760

System Load Factor: 61.5696% = (94,329,844,000 / 17,489,545) / 8,760

column(4)=LF x column(3) / 8760

column(5)=column(4) / (column(4)Total

column(6)=(column(1)+column(2))/2

column(7)=(1-LF) x column(6)

column(8)=column(7) / column(7)Total

column(9)=column(5) x LF + column(8) x (1-LF)

Duke Energy Carolinas

DEC Exhibit 5

Average & Excess Demand Allocation Method

Year: 2018

	Inputs			Calculation						
	Summer Coin. Peak June	MWH @ Gen	NCD (kW)	Average Demand (KW)	Class Load Factor	Excess Demand (Hourly kW)	Average Demand Component (KW)	Excess Demand Component (KW)	Average & Excess Demand	Average & Excess Hourly Demand Ratio
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
North Carolina:										
Residential	5,420,002	23,793,860	12,761,819	2,716,194	50.11%	10,045,625	1,672,350	3,860,572	5,532,922	38.86%
SGS	1,173,097	4,791,551	1,856,082	546,981	46.63%	1,309,101	336,774	503,092	839,866	5.90%
LGS	1,094,460	5,390,752	1,479,187	615,383	56.23%	863,805	378,889	331,963	710,852	4.99%
Lighting	1,270	725,804	207,752	82,854	6523.96%	124,897	51,013	47,999	99,012	0.70%
Industrial	365,855	2,144,966	706,475	244,859	66.93%	461,616	150,759	177,401	328,160	2.31%
OPT-Small	1,445,244	8,544,626	1,638,526	975,414	67.49%	663,112	600,559	254,837	855,395	6.01%
OPT-Medium	484,083	3,309,507	560,748	377,798	78.04%	182,951	232,609	70,309	302,917	2.13%
OPT-Large	1,661,833	12,187,525	1,840,166	1,391,270	83.72%	448,896	856,600	172,512	1,029,112	7.23%
OPT-Trans	148,149	1,258,942	165,874	143,715	97.01%	22,159	88,485	8,516	97,001	0.68%
NC Retail	11,793,993	62,147,533	21,216,630	7,094,467	60.15%	14,122,163	4,368,037	5,427,200	9,795,237	68.80%
NC Wholesale	725,919	4,965,845	1,141,365	566,877	78.09%	574,488	349,024	220,778	569,802	4.00%
Total NC	12,519,912	67,113,378	22,357,995	7,661,344	61.19%	14,696,650	4,717,061	5,647,978	10,365,039	72.81%
South Carolina:										
Residential	1,681,673	7,219,706	4,082,919	824,167	49.01%	3,258,752	507,437	1,252,351	1,759,787	12.36%
SGS	335,555	1,428,590	537,378	163,081	48.60%	374,297	100,408	143,844	244,252	1.72%
LGS	254,778	1,210,028	366,644	138,131	54.22%	228,513	85,047	87,819	172,865	1.21%
Lighting	280	234,925	65,659	26,818	9577.83%	38,841	16,512	14,927	31,439	0.22%
Industrial	151,075	804,037	223,708	91,785	60.75%	131,923	56,512	50,698	107,210	0.75%
OPT-G	526,432	3,194,096	605,976	364,623	69.26%	241,353	224,497	92,753	317,250	2.23%
OPT-I	1,130,670	8,736,687	1,337,197	997,339	88.21%	339,858	614,058	130,609	744,666	5.23%
SC Retail	4,080,463	22,828,069	7,219,481	2,605,944	63.86%	4,613,537	1,604,470	1,772,999	3,377,469	23.72%
SC Wholesale	877,626	4,335,679	952,046	494,940	56.40%	457,106	304,733	175,667	480,400	3.37%
Greenwood	11,544	52,719	32,171	6,018	52.13%	26,153	3,705	10,051	13,756	0.10%
Total SC	4,969,633	27,216,467	8,203,698	3,106,903	62.52%	5,096,795	1,912,908	1,958,718	3,871,626	27.19%
SYSTEM	17,489,545	94,329,844	30,561,692	10,768,247	61.57%	19,793,445	6,629,969	7,606,696	14,236,665	100.00%

Hours in Year: 8,760

System Load Factor: 61.5696% = (94,329,844,000 / 17,489,545) / 8,760

column(4)=column(2)/8760

column(5)=column(4)/column(1)

column(6)=column(3)-column(4)

column(7)=(column(4)/(column(4) Total))xLoad Factor

column(8)=(column(6)/(column(6) Total))x(1-Load Factor)

column(9)=column(7)+column(8)

column(10)=column(9)*column(10) Total

Duke Energy Carolinas

DEC Exhibit 6

Average & Excess Demand - 4CP Allocation Method

Year: 2018

	Inputs			Calculation						
	Summer Coin. Peak June	MWH @ Gen	4CP (kW)	Average Demand (KW)	Class Load Factor	Excess Demand (Hourly kW)	Average Demand Component (KW)	Excess Demand Component (KW)	Average & Excess Demand	Average & Excess Hourly Demand Ratio
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
North Carolina:										
Residential	5,420,002	23,793,860	5,630,276	2,716,194	50.11%	2,914,082	1,672,350	1,119,893	2,792,243	30.56%
SGS	1,173,097	4,791,551	1,008,736	546,981	46.63%	461,755	336,774	177,454	514,228	5.63%
LGS	1,094,460	5,390,752	1,029,595	615,383	56.23%	414,212	378,889	159,183	538,072	5.89%
Lighting	1,270	725,804	30,504	82,854	6523.96%	-52,351	51,013	-20,119	30,894	0.34%
Industrial	365,855	2,144,966	394,207	244,859	66.93%	149,347	150,759	57,395	208,154	2.28%
OPT-Small	1,445,244	8,544,626	1,319,410	975,414	67.49%	343,996	600,559	132,199	732,757	8.02%
OPT-Medium	484,083	3,309,507	456,370	377,798	78.04%	78,572	232,609	30,196	262,804	2.88%
OPT-Large	1,661,833	12,187,525	1,523,839	1,391,270	83.72%	132,569	856,600	50,947	907,546	9.93%
OPT-Trans	148,149	1,258,942	143,904	143,715	97.01%	189	88,485	73	88,557	0.97%
NC Retail	11,793,993	62,147,533	11,536,839	7,094,467	60.15%	4,442,372	4,368,037	1,707,220	6,075,257	66.49%
NC Wholesale	725,919	4,965,845	856,530	566,877	78.09%	289,652	349,024	111,315	460,339	5.04%
Total NC	12,519,912	67,113,378	12,393,368	7,661,344	61.19%	4,732,024	4,717,061	1,818,535	6,535,596	71.53%
South Carolina:										
Residential	1,681,673	7,219,706	1,762,434	824,167	49.01%	938,267	507,437	360,579	868,016	9.50%
SGS	335,555	1,428,590	291,721	163,081	48.60%	128,640	100,408	49,437	149,845	1.64%
LGS	254,778	1,210,028	238,970	138,131	54.22%	100,839	85,047	38,753	123,800	1.35%
Lighting	280	234,925	9,715	26,818	9577.83%	-17,103	16,512	-6,573	9,939	0.11%
Industrial	151,075	804,037	147,304	91,785	60.75%	55,519	56,512	21,336	77,848	0.85%
OPT-G	526,432	3,194,096	482,456	364,623	69.26%	117,833	224,497	45,284	269,781	2.95%
OPT-I	1,130,670	8,736,687	1,091,723	997,339	88.21%	94,385	614,058	36,272	650,330	7.12%
SC Retail	4,080,463	22,828,069	4,024,323	2,605,944	63.86%	1,418,379	1,604,470	545,088	2,149,558	23.53%
SC Wholesale	877,626	4,335,679	862,795	494,940	56.40%	367,854	304,733	141,368	446,101	4.88%
Greenwood	11,544	52,719	11,839	6,018	52.13%	5,821	3,705	2,237	5,942	0.07%
Total SC	4,969,633	27,216,467	4,898,956	3,106,903	62.52%	1,792,054	1,912,908	688,693	2,601,601	28.47%
SYSTEM	17,489,545	94,329,844	17,292,325	10,768,247	61.57%	6,524,078	6,629,969	2,507,228	9,137,197	100.00%

Hours in Year: 8,760

System Load Factor: 61.5696% = (94,329,844,000 / 17,489,545) / 8,760

column(4)=column(2)/8760

column(5)=column(4)/column(1)

column(6)=column(3)-column(4)

column(7)=(column(4)/(column(4) Total))xLoad Factor

column(8)=(column(6)/(column(6) Total))x(1-Load Factor)

column(9)=column(7)+column(8)

column(10)=column(9)*column(10) Total

Duke Energy Carolinas

DEC Exhibit 7

Average & Excess Demand Allocation - Dominion Method

Year: 2018

	Inputs			Calculation						
					System	Excess =		Allocation	Average	Average &
	Summer		Diversified	Average	Peak	NCD Less		of	& Excess	Excess
	Coin. Peak	MWH @	NCD	Demand	Less Avg	Avg Dmnd	Ratio	NCD Excess	Demand	Demand
	June	Gen	(kW)	(KW)	Dmnd	(kW)	(%)	(KW)	(KW)	Ratio
	(1)	(2)	(3)	(4)=(2)/ 8,760	(5)=(1)-(4)	(6)=(3)-(4)	(7)=(5)/(6)	(8)=(6)x 75.55%	(9)=(4)+(8)	(10)
North Carolina:										
Residential	5,420,002	23,793,860	6,325,239	2,716,194		3,609,045		2,726,742	5,442,936	31.12%
SGS	1,173,097	4,791,551	1,141,313	546,981		594,332		449,036	996,016	5.69%
LGS	1,094,460	5,390,752	1,119,464	615,383		504,082		380,849	996,232	5.70%
Lighting	1,270	725,804	205,342	82,854		122,488		92,543	175,397	1.00%
Industrial	365,855	2,144,966	552,183	244,859		307,324		232,192	477,051	2.73%
OPT-Small	1,445,244	8,544,626	1,358,144	975,414		382,730		289,164	1,264,578	7.23%
OPT-Medium	484,083	3,309,507	501,752	377,798		123,955		93,652	471,449	2.70%
OPT-Large	1,661,833	12,187,525	1,699,133	1,391,270		307,863		232,600	1,623,870	9.28%
OPT-Trans	148,149	1,258,942	159,222	143,715		15,507		11,716	155,431	0.89%
NC Retail	11,793,993	62,147,533	13,061,793	7,094,467		5,967,325		4,508,493	11,602,960	66.34%
NC Wholesale	725,919	4,965,845	1,141,365	566,877		574,488		434,043	1,000,920	5.72%
Total NC	12,519,912	67,113,378	14,203,158	7,661,344		6,541,813		4,942,536	12,603,880	72.07%
South Carolina:										
Residential	1,681,673	7,219,706	1,916,284	824,167		1,092,117		825,127	1,649,294	9.43%
SGS	335,555	1,428,590	335,245	163,081		172,164		130,075	293,156	1.68%
LGS	254,778	1,210,028	287,912	138,131		149,781		113,164	251,295	1.44%
Lighting	280	234,925	66,372	26,818		39,554		29,884	56,702	0.32%
Industrial	151,075	804,037	180,328	91,785		88,543		66,897	158,682	0.91%
OPT-G	526,432	3,194,096	488,392	364,623		123,769		93,511	458,134	2.62%
OPT-I	1,130,670	8,736,687	1,204,932	997,339		207,594		156,843	1,154,182	6.60%
SC Retail	4,080,463	22,828,069	4,479,465	2,605,944		1,873,521		1,415,502	4,021,445	22.99%
SC Wholesale	877,626	4,335,679	952,046	494,940		457,106		345,357	840,297	4.80%
Greenwood	11,544	52,719	29,715	6,018		23,697		17,904	23,922	0.14%
Total SC	4,969,633	27,216,467	5,461,226	3,106,903		2,354,324		1,778,762	4,885,665	27.93%
SYSTEM	17,489,545	94,329,844	19,664,384	10,768,247	6,721,298	8,896,137	75.55%	6,721,298	17,489,545	100.00%

Hours in Year: 8,760

Duke Energy Carolinas, LLC

DEC Exhibit 8

Base, Intermediate & Peak - Hydro Summarized

Year: 2018

Generating Plant	Fuel Type	Capacity MW	Average Fuel Cost $/kWh	Net mWh	Annual Capacity Factor	Gross Plant $	Pct Energy	Gross Investment Energy	Gross Investment Demand
Base Load Units:									
Catawba	Nuclear	445	6.30	3,614,344	92.8%	848,785,604	100%	848,785,604	-
McGuire	Nuclear	2,316	6.17	19,862,068	97.9%	3,325,889,462	100%	3,325,889,462	-
Oconee	Nuclear	2,554	6.10	21,294,245	95.2%	4,346,860,741	100%	4,346,860,741	-
Cliffside - Unit 6	Gas	844	47.96	4,311,825	58.3%	1,801,928,192	100%	1,801,928,192	-
Buck Steam CC	Gas	668	28.94	5,173,061	88.4%	625,046,454	100%	625,046,454	-
Dan River CC	Gas	662	30.08	4,967,660	88.4%	647,353,043	100%	647,353,043	-
Lee CC	Gas	753	24.84	3,523,669	85.7%	553,446,598	100%	553,446,598	-
Total Base Load Units		8,241		62,746,872		12,149,310,094		12,149,310,094	-
Intermediate Units:									
Belews Creek	Coal	2,220	30.41	8,021,417	41.2%	2,208,964,382	41.2%	911,134,993	1,297,829,388
Cliffside - Unit 5	Coal	544	30.66	1,242,648	26.1%	1,161,432,389	26.1%	302,858,037	858,574,352
Marshall	Coal	2,058	29.53	8,486,270	47.1%	1,750,490,966	47.1%	824,000,058	926,490,908
Total Intermediate Units		4,822		17,750,335		5,120,887,737		2,037,993,089	3,082,894,648
Peaking Units:									
Allen	Coal	1,098	37.86	819,761	8.5%	1,237,322,437	0.0%	-	1,237,322,437
Lee	Gas	180	24.84	54,152	3.4%	113,252,956	0.0%	-	113,252,956
Lincoln CT	Gas	1,193	318.15	82,484	0.8%	408,308,728	0.0%	-	408,308,728
Mill Creek CT	Gas	563	69.26	201,194	4.1%	255,955,475	0.0%	-	255,955,475
Rockingham CT	Gas	825	40.28	2,325,235	32.2%	304,373,541	0.0%	-	304,373,541
Lee CT	Gas	84	53.47	79,514	10.8%	61,654,879	0.0%	-	61,654,879
DEC On-Site Generators						17,731,892	0.0%	-	17,731,892
Total Peaking Units		3,943		3,562,340		2,398,599,908		-	2,398,599,908
Hydro Units:									
Bad Creek	Pumped Storage	1,360		1,447,036	12.1%	1,021,400,662	50.0%	510,700,331	510,700,331
Jocassee	Pumped Storage	780		1,204,730	17.6%	175,327,093	50.0%	87,663,546	87,663,546
Storage	Storage	964		2,230,656	26.4%	880,512,113	50.0%	440,256,057	440,256,057
Run-of-River	Run-of-River	141		646,398	52.3%	109,296,164	100.0%	109,296,164	-
Total Hydro Units		3,245		5,528,820		2,186,536,032		1,147,916,098	1,038,619,934
Solar Units:									
DEC Solar		2.4				42,438,732	47.3%	20,060,055	22,378,677
Mocksville - Solar		6.2				31,773,280	47.3%	15,018,680	16,754,599
Monroe - Solar		21.8				116,568,189	47.3%	55,099,769	61,468,420
Total Renewable Units		31.4		130,018	47.3%	190,780,201		90,178,505	100,601,696
Total System		20,283		89,718,385		22,046,113,971		15,425,397,785	6,620,716,186
Percent of Total								70.0%	30.0%

Duke Energy Carolinas, LLC
Base, Intermediate & Peak Allocation Method
Development of DEC BIP Plant Composite Allocator

DEC Exhibit 9

		Factor	Total Company	NC Retail	NCRS	NCRT	NCRE	RES	NCSGS	NCLGS
Plant-in-Service										
Base	Energy	Energy	12,149,310,094	8,004,355,885	1,735,495,027	6,723,411	1,322,336,406	3,064,554,844	617,132,774	694,307,488
	Demand	SCP	0	0	0	0	0	0	0	0
	Total		12,149,310,094	8,004,355,885	1,735,495,027	6,723,411	1,322,336,406	3,064,554,844	617,132,774	694,307,488
Intermediate	Energy	Energy	2,037,993,089	1,342,695,334	291,121,623	1,127,822	221,816,090	514,065,535	103,521,296	116,467,013
	Demand	12CP	3,082,894,648	2,055,328,017	528,804,435	2,123,504	439,760,855	970,688,795	170,235,181	188,940,064
	Total		5,120,887,737	3,398,023,351	819,926,058	3,251,327	661,576,945	1,484,754,330	273,756,478	305,407,077
Peaking	Energy	Energy	0	0	0	0	0	0	0	0
	Demand	SCP	2,398,599,908	1,617,484,647	477,945,602	1,516,136	263,863,277	743,325,015	160,884,137	150,099,483
	Total		2,398,599,908	1,617,484,647	477,945,602	1,516,136	263,863,277	743,325,015	160,884,137	150,099,483
Pumped Storage	Energy	Energy	598,363,878	394,221,350	85,474,609	331,134	65,126,195	150,931,938	30,394,315	34,195,236
	Demand	SCP	598,363,878	403,503,887	119,230,132	378,221	65,824,339	185,432,692	40,134,770	37,444,389
	Total		1,196,727,755	797,725,236	204,704,741	709,355	130,950,534	336,364,630	70,529,085	71,639,625
Run-of-River	Energy	Energy	109,296,164	72,007,825	15,612,652	60,484	11,895,844	27,568,980	5,551,776	6,246,046
	Demand	SCP	0	0	0	0	0	0	0	0
	Total		109,296,164	72,007,825	15,612,652	60,484	11,895,844	27,568,980	5,551,776	6,246,046
Storage	Energy	Energy	440,256,057	290,054,837	62,889,349	243,637	47,917,668	111,050,654	22,363,117	25,159,707
	Demand	SCP	440,256,057	296,884,616	87,725,529	278,282	48,431,339	136,435,151	29,529,817	27,550,325
	Total		880,512,113	586,939,453	150,614,878	521,919	96,349,008	247,485,805	51,892,934	52,710,031
Solar	Energy	Energy	90,178,505	59,412,496	12,881,748	49,905	9,815,069	22,746,721	4,580,681	5,153,512
	Demand	12CP	100,601,696	67,069,916	17,256,063	69,295	14,350,373	31,675,730	5,555,152	6,165,534
	Total		190,780,201	126,482,413	30,137,810	119,199	24,165,442	54,422,452	10,135,833	11,319,045
Total			22,046,113,971	14,603,018,810	3,434,436,769	12,901,831	2,511,137,456	5,958,476,056	1,189,883,016	1,291,728,794
Check:										
Plant_BIP_Composite_Factor ==>			100.0000%	66.2385%	15.5784%	0.0585%	11.3904%	27.0273%	5.3972%	5.8592%

Duke Energy Carolinas, Inc.

DEC Exhibit 10

Cost of Service Analysis Results
Production Demand Allocation Factors
For the twelve months ending December 2018

		Peak Responsibility Methods				Energy Weighting Methods				Time Differentiated Method
	Load Factor	Summer 1 CP	Winter 1 CP	4CP	12CP	SWPA	A&E	A&E 4CP	A&E Dom	BIP
		Exhibit3	Exhibit3	Exhibit3	Exhibit3	Exhibit4	Exhibit5	Exhibit6	Exhibit7	Exhibit8
North Carolina:										
Residential	50.11%	30.9900%	36.6484%	32.5594%	31.4863%	29.6899%	38.8639%	30.5591%	31.1211%	27.0273%
SGS	46.63%	6.7074%	5.2708%	5.8334%	5.5219%	5.5322%	5.8993%	5.6279%	5.6949%	5.3972%
LGS	56.23%	6.2578%	5.3386%	5.9541%	6.1287%	5.7486%	4.9931%	5.8888%	5.6962%	5.8592%
Lighting		0.0073%	0.4168%	0.1764%	0.1332%	0.4874%	0.6955%	0.3381%	1.0029%	0.5587%
Industrial	66.93%	2.0918%	2.0516%	2.2797%	2.3447%	2.1698%	2.3050%	2.2781%	2.7276%	2.2557%
OPT-Small	67.49%	8.2635%	7.0243%	7.6300%	7.7505%	8.3204%	6.0084%	8.0195%	7.2305%	8.7455%
OPT-Medium	78.04%	2.7678%	2.3229%	2.6391%	2.7923%	3.0099%	2.1277%	2.8762%	2.6956%	3.2896%
OPT-Large	83.72%	9.5019%	7.2610%	8.8122%	9.5791%	10.5692%	7.2286%	9.9324%	9.2848%	11.9047%
OPT-Trans	97.01%	0.8471%	0.6880%	0.8322%	0.9322%	1.0421%	0.6813%	0.9692%	0.8887%	1.2005%
NC Retail		67.4345%	67.0222%	66.7165%	66.6688%	66.5694%	68.8029%	66.4893%	66.3423%	66.2385%
NC Wholesale	78.09%	4.1506%	5.8272%	4.9532%	4.8449%	5.1394%	4.0024%	5.0381%	5.7230%	5.0301%
Total NC	61.19%	71.5851%	72.8494%	71.6698%	71.5137%	71.7088%	72.8052%	71.5274%	72.0652%	71.2687%
South Carolina:										
Residential	49.01%	9.6153%	10.8916%	10.1920%	10.0098%	9.0002%	12.3610%	9.4998%	9.4302%	8.2998%
SGS	48.60%	1.9186%	1.4200%	1.6870%	1.6619%	1.5890%	1.7157%	1.6399%	1.6762%	1.5988%
LGS	54.22%	1.4567%	1.2166%	1.3819%	1.3633%	1.3081%	1.2142%	1.3549%	1.4368%	1.3215%
Lighting		0.0016%	0.1312%	0.0562%	0.0420%	0.1566%	0.2208%	0.1088%	0.3242%	0.1806%
Industrial	60.75%	0.8638%	0.7101%	0.8518%	0.8673%	0.8173%	0.7531%	0.8520%	0.9073%	0.8563%
OPT-G	69.26%	3.0100%	2.5992%	2.7900%	2.8590%	3.0837%	2.2284%	2.9526%	2.6195%	3.2513%
OPT-I	88.21%	6.4648%	5.0703%	6.3133%	6.7756%	7.4552%	5.2306%	7.1174%	6.5993%	8.4667%
SC Retail		23.3309%	22.0390%	23.2723%	23.5790%	23.4101%	23.7237%	23.5254%	22.9934%	23.9750%
Greenwood	52.13%	0.0660%	0.0687%	0.0685%	0.0688%	0.0618%	0.0966%	0.0650%	4.8046%	0.0593%
SC Wholesale	56.40%	5.0180%	5.0428%	4.9895%	4.8385%	4.8193%	3.3744%	4.8823%	0.1368%	4.6970%
Total SC	62.52%	28.4149%	27.1506%	28.3302%	28.4863%	28.2912%	27.1948%	28.4726%	27.9348%	28.7313%
System		100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

Duke Energy Carolinas, Inc.

DEC Exhibit 11

Cost of Service Analysis Results
Present Rate of Return on Rate Base
For the twelve months ending December 2018

		Peak Responsibility Methods				Energy Weighting Methods				Time Differentiated Method	
	Load Factor	Summer 1 CP	Winter 1 CP	4CP	12CP	SWPA	A&E	A&E 4CP	A&E Dom	BIP	Average of Returns
North Carolina:											
Residential	50.11%	5.56%	4.20%	5.16%	5.43%	5.79%	3.90%	5.66%	5.53%	6.63%	5.32%
SGS	46.63%	7.00%	9.58%	8.48%	9.09%	8.97%	8.21%	8.67%	8.56%	9.10%	8.63%
LGS	56.23%	6.13%	8.10%	6.73%	6.38%	7.15%	8.66%	6.80%	7.17%	6.89%	7.11%
Lighting		4.11%	2.97%	3.61%	3.74%	2.85%	2.43%	3.25%	1.80%	2.67%	3.05%
Industrial	66.93%	8.08%	8.30%	7.04%	6.72%	7.68%	7.02%	7.15%	5.25%	7.28%	7.17%
OPT-Small	67.49%	5.07%	6.97%	5.99%	5.81%	5.08%	8.49%	5.38%	6.47%	4.43%	5.96%
OPT-Medium	78.04%	5.58%	7.67%	6.13%	5.48%	4.79%	8.42%	5.18%	5.86%	3.74%	5.87%
OPT-Large	83.72%	4.44%	7.52%	5.26%	4.36%	3.52%	7.21%	4.01%	4.67%	2.22%	4.80%
OPT-Trans	97.01%	5.60%	8.15%	5.81%	4.51%	3.56%	7.98%	4.21%	5.10%	2.02%	5.22%
NC Retail		5.58%	5.62%	5.67%	5.68%	5.68%	5.41%	5.69%	5.71%	5.73%	5.64%
South Carolina:											
Residential	49.01%	7.88%	6.56%	7.26%	7.46%	8.42%	5.50%	7.99%	8.06%	9.39%	7.61%
SGS	48.60%	11.19%	15.36%	12.93%	13.14%	13.69%	12.54%	13.09%	12.84%	13.44%	13.13%
LGS	54.22%	13.10%	16.79%	14.12%	14.40%	15.19%	16.37%	14.37%	13.34%	14.86%	14.73%
Lighting		3.16%	1.91%	2.62%	2.76%	1.80%	1.38%	2.23%	0.66%	1.61%	2.01%
Industrial	60.75%	22.13%	27.32%	22.47%	22.02%	23.62%	25.24%	22.43%	21.06%	22.31%	23.18%
OPT-G	69.26%	9.65%	12.26%	10.96%	10.54%	9.38%	14.55%	9.94%	11.85%	8.37%	10.83%
OPT-I	88.21%	4.83%	8.25%	5.14%	4.23%	3.29%	7.47%	3.71%	4.58%	1.69%	4.80%
SC Retail Excl GW		8.22%	8.92%	8.24%	8.09%	8.20%	8.03%	8.12%	8.38%	7.90%	8.23%

Duke Energy Carolinas, Inc.

DEC Exhibit 12

Cost of Service Analysis Results
Rate of Return on Rate Base Index
For the twelve months ending December 2018

		Peak Responsibility Methods				Energy Weighting Methods				Time Differentiated Method
	Load Factor	Summer 1 CP	Winter 1 CP	4CP	12CP	SWPA	A&E	A&E 4CP	A&E Dom	BIP
North Carolina:										
Residential	50.11%	99.66%	74.78%	90.91%	95.56%	101.90%	72.03%	99.41%	96.76%	115.73%
SGS	46.63%	125.51%	170.55%	149.62%	159.96%	157.97%	151.83%	152.24%	149.78%	158.90%
LGS	56.23%	109.88%	144.18%	118.67%	112.32%	126.01%	160.10%	119.35%	125.46%	120.22%
Lighting		73.67%	52.80%	63.71%	65.74%	50.15%	44.89%	57.08%	31.57%	46.54%
Industrial	66.93%	144.95%	147.79%	124.17%	118.22%	135.32%	129.80%	125.63%	91.96%	126.99%
OPT-Small	67.49%	90.93%	124.06%	105.59%	102.26%	89.38%	156.90%	94.49%	113.26%	77.29%
OPT-Medium	78.04%	100.03%	136.52%	108.09%	96.44%	84.38%	155.59%	91.02%	102.53%	65.23%
OPT-Large	83.72%	79.65%	133.78%	92.80%	76.69%	62.01%	133.26%	70.51%	81.73%	38.79%
OPT-Trans	97.01%	100.44%	145.16%	102.38%	79.42%	62.75%	147.54%	73.97%	89.27%	35.17%
NC Retail		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
South Carolina:										
Residential	49.01%	95.87%	73.57%	88.13%	92.22%	102.69%	68.50%	98.39%	96.21%	118.91%
SGS	48.60%	136.10%	172.20%	156.87%	162.45%	166.89%	156.14%	161.17%	153.16%	170.22%
LGS	54.22%	159.34%	188.25%	171.33%	178.04%	185.16%	203.91%	176.92%	159.18%	188.16%
Lighting		38.44%	21.45%	31.81%	34.17%	21.92%	17.17%	27.45%	7.86%	20.38%
Industrial	60.75%	269.31%	306.37%	272.61%	272.26%	287.92%	314.38%	276.11%	251.23%	282.48%
OPT-G	69.26%	117.41%	137.44%	132.97%	130.27%	114.32%	181.19%	122.40%	141.41%	105.99%
OPT-I	88.21%	58.80%	92.53%	62.33%	52.30%	40.07%	93.08%	45.70%	54.68%	21.45%
SC Retail Excl GW		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Duke Energy Carolinas, LLC

DEC Exhibit 13

Alternative Fuel Allocation Method

Year: 2018

Intermediate Method: 12CP   Peak Method: 1CP-Sum

Rate	Base				Intermediate			Peak		
Rate Class	Sales at Generator kWh	Average Annual Hourly Demand KW	Base Period Ratio 58.77%	Base as % of Total	12 CP Demand KW	Demand Peak Ratio 27.90%	Intermediate as % of Total	1CP-Sum Peak Demand KW	Demand Ratio 13.33%	Peak as % of Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
North Carolina:										
Residential	23,793,860,000	2,716,194	1,596,236	25.2241%	4,981,655	1,389,793	31.4863%	5,420,002	722,725	30.9900%
SGS	4,791,551,000	546,981	321,446	5.0796%	873,661	243,736	5.5219%	1,173,097	156,425	6.7074%
LGS	5,390,752,000	615,383	361,644	5.7148%	969,656	270,517	6.1287%	1,094,460	145,940	6.2578%
Lighting	725,804,000	82,854	48,691	0.7694%	21,076	5,880	0.1332%	1,270	169	0.0073%
Industrial	2,144,966,000	244,859	143,897	2.2739%	370,964	103,492	2.3447%	365,855	48,785	2.0918%
OPT-Small	8,544,626,000	975,414	573,225	9.0582%	1,226,252	342,103	7.7505%	1,445,244	192,715	8.2635%
OPT-Medium	3,309,507,000	377,798	222,022	3.5084%	441,781	123,249	2.7923%	484,083	64,550	2.7678%
OPT-Large	12,187,525,000	1,391,270	817,613	12.9201%	1,515,575	422,819	9.5791%	1,661,833	221,596	9.5019%
OPT-Trans	1,258,942,000	143,715	84,457	1.3346%	147,493	41,148	0.9322%	148,149	19,755	0.8471%
NC Retail	62,147,533,000	7,094,467	4,169,232	65.8832%	10,548,113	2,942,736	66.6688%	11,793,993	1,572,659	67.4345%
NC Wholesale	4,965,844,574	566,877	333,139	5.2643%	766,552	213,854	4.8449%	725,919	96,797	4.1506%
Total NC	67,113,377,574	7,661,344	4,502,371	71.1476%	11,314,664	3,156,590	71.5137%	12,519,912	1,669,456	71.5851%
South Carolina:										
Residential	7,219,706,000	824,167	484,342	7.6537%	1,583,722	441,830	10.0098%	1,681,673	224,241	9.6153%
SGS	1,428,590,000	163,081	95,838	1.5145%	262,944	73,357	1.6619%	335,555	44,744	1.9186%
LGS	1,210,028,000	138,131	81,176	1.2828%	215,691	60,174	1.3633%	254,778	33,973	1.4567%
Lighting	234,925,000	26,818	15,760	0.2490%	6,646	1,854	0.0420%	280	37	0.0016%
Industrial	804,037,000	91,785	53,940	0.8524%	137,224	38,283	0.8673%	151,075	20,145	0.8638%
OPT-G	3,194,096,000	364,623	214,279	3.3861%	452,349	126,197	2.8590%	526,432	70,197	3.0100%
OPT-I	8,736,687,000	997,339	586,110	9.2618%	1,072,017	299,074	6.7756%	1,130,670	150,768	6.4648%
SC Retail	22,828,069,000	2,605,944	1,531,445	24.2003%	3,730,592	1,040,769	23.5790%	4,080,463	544,105	23.3309%
SC Wholesale	4,335,678,506	494,940	290,864	4.5963%	765,535	213,571	4.8385%	877,626	117,026	5.0180%
Greenwood	52,719,000	6,018	3,537	0.0559%	10,878	3,035	0.0688%	11,544	1,539	0.0660%
Total SC	27,216,466,506	3,106,903	1,825,845	28.8524%	4,507,005	1,257,374	28.4863%	4,969,633	662,671	28.4149%
SYSTEM	94,329,844,080		6,328,216	100.0000%	15,821,669	4,413,964	100.0000%	17,489,545	2,332,127	100.0000%

Hours in Year: 8,760

System Load Factor: 61.5696% = (94,329,844,080 / 17,489,545) / 8,760

column(2) - values are from Data worksheet

column(3)=column(2) / 8,760

column(4)=column(3) x 58.77%

column(5)=column(4) / 6,328,216

Column(6) - values are from DEC Exhibit 2

column(7)=column(6) x 27.90%

column(8)=column(7) / 4,413,964

column(9) - values are from DEC Exhibit 2

column(10)=column(9) x 13.33%

column(11)=column(10) / 2,332,127

Duke Energy Carolinas, LLC

Alternative Fuel Allocation Method

Year: 2018

Fuel - Generation	1,583,377,319
Fuel - Purchased Power	277,523,485
	1,860,900,804

Rate	Base Fuel	Intermediate Fuel	Peak Fuel	Total	Average Fuel ($/kWh)	Increase (Decrease) Over Average
Class	1,084,290,467	592,069,805	184,540,532	1,860,900,804	0.01973	
(1)	(14)=BasexCol(5)	(15)=Int x Col(8)	(16)=Pk x Col(11)	(17)=(14)+(15)+(16)	(18)	(19)=(17)-(18)
North Carolina:						
Residential	273,502,578	186,420,758	57,189,027	517,112,363	469,395,594	47,716,769
SGS	55,077,299	32,693,649	12,377,906	100,148,854	94,525,770	5,623,085
LGS	61,964,917	36,285,921	11,548,170	109,799,008	106,346,563	3,452,445
Lighting	8,342,878	788,710	13,400	9,144,988	14,318,366	-5,173,378
Industrial	24,655,677	13,882,008	3,860,311	42,397,995	42,315,017	82,978
OPT-Small	98,217,660	45,888,131	15,249,459	159,355,249	168,564,907	-9,209,658
OPT-Medium	38,041,692	16,532,073	5,107,791	59,681,556	65,288,608	-5,607,052
OPT-Large	140,091,583	56,715,023	17,534,793	214,341,399	240,430,537	-26,089,138
OPT-Trans	14,471,123	5,519,402	1,563,191	21,553,716	24,835,896	-3,282,180
NC Retail	714,365,409	394,725,674	124,444,046	1,233,535,129	1,226,021,258	7,513,870
NC Wholesale	57,080,747	28,685,468	7,659,513	93,425,728	97,964,162	-4,538,434
Total NC	771,446,155	423,411,142	132,103,560	1,326,960,857	1,323,985,421	2,975,436
South Carolina:						
Residential	82,988,141	59,265,182	17,744,134	159,997,457	142,427,424	17,570,033
SGS	16,421,171	9,839,733	3,540,601	29,801,505	28,182,643	1,618,863
LGS	13,908,873	8,071,454	2,688,284	24,668,612	23,870,940	797,671
Lighting	2,700,385	248,703	2,954	2,952,043	4,634,505	-1,682,462
Industrial	9,242,140	5,135,115	1,594,064	15,971,319	15,861,715	109,605
OPT-G	36,715,081	16,927,568	5,554,635	59,197,284	63,011,827	-3,814,543
OPT-I	100,425,338	40,116,415	11,930,239	152,471,991	172,353,808	-19,881,818
SC Retail	262,401,129	139,604,170	43,054,912	445,060,211	450,342,862	-5,282,651
SC Wholesale	49,837,195	28,647,412	9,260,255	87,744,863	85,532,502	2,212,360
Greenwood	605,988	407,080	121,806	1,134,874	1,040,019	94,855
Total SC	312,844,312	168,658,662	52,436,973	533,939,947	536,915,384	-2,975,436
SYSTEM	1,084,290,467	592,069,805	184,540,532	1,860,900,804	1,860,900,804	0

Duke Energy Carolinas, LLC
Cost of Service Analysis Results
ROR At Present Rates - After Fuel Adjustment
For the twelve months ending December 2018

DEC Exhibit 14
Pg 1 of 2

	After Fuel Adjustment								
	Peak Responsibility Methods				Energy Weighting Methods				Time Differentiated Method
	Summer 1 CP	Winter 1 CP	4CP	12CP	SWPA	A&E	A&E 4CP	A&E Dom	BIP
North Carolina:									
Residential	5.56%	4.20%	5.16%	5.43%	5.23%	3.41%	5.11%	4.98%	6.05%
SGS	7.00%	9.58%	8.48%	9.09%	8.58%	7.84%	8.28%	8.17%	8.71%
LGS	6.13%	8.10%	6.73%	6.38%	6.86%	8.34%	6.50%	6.87%	6.59%
Lighting	4.11%	2.97%	3.61%	3.74%	3.54%	3.10%	3.97%	2.44%	3.35%
Industrial	8.08%	8.30%	7.04%	6.72%	7.67%	7.01%	7.14%	5.24%	7.26%
OPT-Small	5.07%	6.97%	5.99%	5.81%	5.65%	9.19%	5.96%	7.09%	4.97%
OPT-Medium	5.58%	7.67%	6.13%	5.48%	5.76%	9.62%	6.17%	6.89%	4.64%
OPT-Large	4.44%	7.52%	5.26%	4.36%	4.83%	8.87%	5.36%	6.08%	3.40%
OPT-Trans	5.60%	8.15%	5.81%	4.51%	5.29%	10.26%	6.01%	7.01%	3.54%
NC Retail	5.58%	5.62%	5.67%	5.68%	5.63%	5.37%	5.65%	5.67%	5.68%
South Carolina:									
Residential	7.88%	6.56%	7.26%	7.46%	7.65%	4.84%	7.23%	7.30%	8.57%
SGS	11.19%	15.36%	12.93%	13.14%	13.27%	12.13%	12.68%	12.43%	13.02%
LGS	13.10%	16.79%	14.12%	14.40%	14.83%	16.00%	14.03%	13.01%	14.51%
Lighting	3.16%	1.91%	2.62%	2.76%	2.62%	2.17%	3.07%	1.41%	2.41%
Industrial	22.13%	27.32%	22.47%	22.02%	23.54%	25.17%	22.36%	20.99%	22.23%
OPT-G	9.65%	12.26%	10.96%	10.54%	10.15%	15.51%	10.73%	12.71%	9.10%
OPT-I	4.83%	8.25%	5.14%	4.23%	5.01%	9.67%	5.48%	6.45%	3.22%
SC Retail Excl GW	8.22%	8.92%	8.24%	8.09%	8.31%	8.14%	8.23%	8.49%	8.00%

Duke Energy Carolinas, LLC

DEC Exhibit 14

Pg 2 of 2

Cost of Service Analysis Results
ROR At Present Rates - After Fuel Adj less Before Fuel Adj
For the twelve months ending December 2018

	After Fuel Adjustment less Before Fuel Adjustment								
	Peak Responsibility Methods				Energy Weighting Methods				Time Differentiated Method
	Summer 1 CP	Winter 1 CP	4CP	12CP	SWPA	A&E	A&E 4CP	A&E Dom	BIP
North Carolina:									
Residential	0.00%	0.00%	0.00%	0.00%	-0.55%	-0.49%	-0.55%	-0.54%	-0.58%
SGS	0.00%	0.00%	0.00%	0.00%	-0.39%	-0.38%	-0.38%	-0.38%	-0.39%
LGS	0.00%	0.00%	0.00%	0.00%	-0.30%	-0.32%	-0.29%	-0.30%	-0.29%
Lighting	0.00%	0.00%	0.00%	0.00%	0.69%	0.67%	0.72%	0.64%	0.69%
Industrial	0.00%	0.00%	0.00%	0.00%	-0.02%	-0.02%	-0.02%	-0.02%	-0.02%
OPT-Small	0.00%	0.00%	0.00%	0.00%	0.57%	0.70%	0.58%	0.62%	0.55%
OPT-Medium	0.00%	0.00%	0.00%	0.00%	0.97%	1.20%	0.99%	1.04%	0.90%
OPT-Large	0.00%	0.00%	0.00%	0.00%	1.31%	1.66%	1.35%	1.41%	1.18%
OPT-Trans	0.00%	0.00%	0.00%	0.00%	1.73%	2.28%	1.80%	1.91%	1.53%
NC Retail	0.00%	0.00%	0.00%	0.00%	-0.04%	-0.04%	-0.04%	-0.04%	-0.04%
South Carolina:									
Residential	0.00%	0.00%	0.00%	0.00%	-0.78%	-0.66%	-0.76%	-0.77%	-0.81%
SGS	0.00%	0.00%	0.00%	0.00%	-0.42%	-0.40%	-0.41%	-0.41%	-0.42%
LGS	0.00%	0.00%	0.00%	0.00%	-0.36%	-0.37%	-0.35%	-0.33%	-0.35%
Lighting	0.00%	0.00%	0.00%	0.00%	0.82%	0.79%	0.84%	0.75%	0.80%
Industrial	0.00%	0.00%	0.00%	0.00%	-0.07%	-0.08%	-0.07%	-0.07%	-0.07%
OPT-G	0.00%	0.00%	0.00%	0.00%	0.77%	0.96%	0.79%	0.86%	0.73%
OPT-I	0.00%	0.00%	0.00%	0.00%	1.72%	2.20%	1.76%	1.87%	1.53%
SC Retail Excl GW	0.00%	0.00%	0.00%	0.00%	0.11%	0.11%	0.11%	0.11%	0.11%

Duke Energy Carolinas, LLC

DEC Exhibit 15

Single Summer CP Method

Unit Cost Report

Year: 2018

	Demand	UNIT	COSTS	Energy	UNIT	COSTS	CUSTOMER	UNIT	COSTS
	Revenue	KW [1]	$/KW/Mo	Revenue	Annual MWH [2]	Cents/KWH	Revenue	Avg Bills [3]	$/Cust/Mo
North Carolina:									
Residential	1,346,689,611	5,420,002	20.71	526,109,965	22,763,030	2.31	470,177,117	1,756,541	22.31
SGS	294,299,359	1,173,097	20.91	114,420,455	4,567,331	2.51	68,973,083	242,917	23.66
LGS	256,197,441	1,094,460	19.51	129,636,327	5,142,000	2.52	2,519,931	9,171	22.90
Lighting	98,775,718	1,270	-	16,796,317	691,829	2.43	19,449,674	291,039	5.57
Industrial	96,343,394	365,855	21.94	49,906,598	2,048,172	2.44	1,077,248	3,707	24.22
OPT-Small	315,111,691	1,445,244	31.49	203,645,383	8,149,226	4.92	4,436,244	16,808	36.22
OPT-Medium	107,128,640	484,083	36.46	77,952,613	3,162,303	4.94	92,154	355	40.80
OPT-Large	332,887,579	1,661,833	33.48	285,399,407	11,720,190	4.86	48,040	215	38.02
OPT-Transmission	28,141,179	148,149	15.83	31,157,210	1,236,620	2.52	272	4	5.67
TOTAL RETAIL	$ 2,875,574,611	11,793,993	20.32	$ 1,435,024,274	59,480,701	2.41	$ 566,773,763	2,320,757	20.35

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Carolinas, LLC

DEC Exhibit 16

Single Winter CP Method

Unit Cost Report

Year: 2018

	Demand	UNIT	COSTS	Energy	UNIT	COSTS	CUSTOMER	UNIT	COSTS
	Revenue	KW [1]	$/KW/Mo	Revenue	Annual MWH [2]	Cents/KWH	Revenue	Avg Bills [3]	$/Cust/Mo
North Carolina:									
Residential	1,425,840,620	6,917,677	17.18	522,414,966	22,763,030	2.30	450,714,979	1,756,541	21.38
SGS	269,167,555	994,904	22.55	116,298,037	4,567,331	2.55	76,282,010	242,917	26.17
LGS	244,068,671	1,007,695	20.18	131,299,667	5,142,000	2.55	2,732,759	9,171	24.83
Lighting	103,179,427	78,669		16,660,860	691,829	2.41	19,156,718	291,039	5.49
Industrial	95,709,715	387,247	20.60	49,960,290	2,048,172	2.44	1,084,924	3,707	24.39
OPT-Small	298,316,809	1,325,901	18.75	206,171,435	8,149,226	2.53	4,804,189	16,808	23.82
OPT-Medium	101,123,346	438,459	19.22	79,013,625	3,162,303	2.50	100,330	355	23.55
OPT-Large	302,521,333	1,370,565	18.39	291,224,977	11,720,191	2.48	54,463	215	21.11
OPT-Transmission	25,827,135	129,864	16.57	31,669,185	1,236,620	2.56	280	4	5.83
TOTAL RETAIL	$ 2,865,754,613	12,650,981	18.88	$ 1,444,713,039	59,480,702	2.43	$ 554,930,651	2,320,757	19.93

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Carolinas, LLC

DEC Exhibit 17

4CP - 2 Summer, 2 Winter Method

Unit Cost Report

Year: 2018

	Demand Revenue	UNIT KW [1]	COSTS $/KW/Mo	Energy Revenue	UNIT Annual MWH [2]	COSTS Cents/KWH	CUSTOMER Revenue	UNIT Avg Bills [3]	COSTS $/Cust/Mo
North Carolina:									
Residential	1,365,230,478	5,630,276	20.21	524,326,137	22,763,030	2.30	461,488,117	1,756,541	21.89
SGS	278,475,821	1,008,736	23.01	115,430,523	4,567,331	2.53	72,974,167	242,917	25.03
LGS	251,322,774	1,029,595	20.34	130,056,010	5,142,000	2.53	2,575,852	9,171	23.41
Lighting	100,100,155	30,504		16,723,148	691,829	2.42	19,297,459	291,039	5.53
Industrial	98,308,192	394,207	20.78	49,518,270	2,048,172	2.42	1,027,929	3,707	23.11
OPT-Small	305,541,852	1,319,410	19.30	204,707,349	8,149,226	2.51	4,623,381	16,808	22.92
OPT-Medium	105,028,169	456,370	19.18	78,165,608	3,162,303	2.47	93,929	355	22.05
OPT-Large	322,500,413	1,523,839	17.64	286,715,628	11,720,191	2.45	49,630	215	19.24
OPT-Transmission	27,800,410	143,904	16.10	31,174,283	1,236,620	2.52	272	4	5.68
TOTAL RETAIL	$ 2,854,308,264	11,536,839	20.62	$ 1,436,816,956	59,480,702	2.42	$ 562,130,735	2,320,757	20.18

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Carolinas, LLC

DEC Exhibit 18

12 CP Method

Unit Cost Report

Year: 2018

	Demand Revenue	UNIT KW [1]	COSTS $/KW/Mo	Energy Revenue	UNIT Annual MWH [2]	COSTS Cents/KWH	CUSTOMER Revenue	UNIT Avg Bills [3]	COSTS $/Cust/Mo
North Carolina:									
Residential	1,346,671,139	4,981,655	22.53	525,209,863	22,763,030	2.31	466,641,682	1,756,541	22.14
SGS	272,778,315	873,661	26.02	115,871,140	4,567,331	2.54	74,682,434	242,917	25.62
LGS	253,310,761	969,656	21.77	129,743,583	5,142,000	2.52	2,536,309	9,171	23.05
Lighting	99,527,436	21,076		16,735,720	691,829	2.42	19,319,365	291,039	5.53
Industrial	99,025,306	370,964	22.25	49,405,900	2,048,172	2.41	1,013,379	3,707	22.78
OPT-Small	306,832,507	1,226,252	20.85	204,458,086	8,149,226	2.51	4,592,115	16,808	22.77
OPT-Medium	106,900,755	441,781	20.16	77,817,626	3,162,303	2.46	91,239	355	21.42
OPT-Large	332,042,513	1,515,575	18.26	284,952,683	11,720,190	2.43	47,693	215	18.49
OPT-Transmission	29,123,429	147,493	16.45	30,906,533	1,236,620	2.50	268	4	5.59
TOTAL RETAIL	$ 2,846,212,162	10,548,113	22.49	$ 1,435,101,133	59,480,701	2.41	$ 568,924,485	2,320,757	20.43

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Carolinas, LLC

DEC Exhibit 19

SWPA Method

Unit Cost Report

Year: 2018

	Demand Revenue	UNIT KW [1]	COSTS $/KW/Mo	Energy Revenue	UNIT Annual MWH [2]	COSTS Cents/KWH	CUSTOMER Revenue	UNIT Avg Bills [3]	COSTS $/Cust/Mo
North Carolina:									
Residential	1,324,781,796	4,043,058	27.31	526,507,667	22,763,030	2.31	474,331,558	1,756,541	22.50
SGS	273,964,308	753,359	30.30	115,781,359	4,567,331	2.53	74,347,718	242,917	25.51
LGS	248,714,930	782,822	26.48	130,413,806	5,142,000	2.54	2,621,919	9,171	23.82
Lighting	103,241,854	66,375		16,637,065	691,829	2.40	19,093,967	291,039	5.47
Industrial	96,793,644	295,469	27.30	49,727,938	2,048,172	2.43	1,055,465	3,707	23.73
OPT-Small	313,507,359	1,133,041	23.06	203,427,034	8,149,226	2.50	4,428,215	16,808	21.95
OPT-Medium	109,099,919	409,877	22.18	77,455,715	3,162,303	2.45	88,467	355	20.77
OPT-Large	341,814,505	1,439,281	19.79	283,350,039	11,720,191	2.42	45,893	215	17.79
OPT-Transmission	30,210,860	141,906	17.74	30,711,981	1,236,620	2.48	266	4	5.53
TOTAL RETAIL	$ 2,842,129,174	9,065,188	26.13	$ 1,434,012,603	59,480,702	2.41	$ 576,013,467	2,320,757	20.68

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Carolinas, LLC

DEC Exhibit 20

Average & Excess Method

Unit Cost Report

Year: 2018

	Demand Revenue	UNIT KW [1]	COSTS $/KW/Mo	Energy Revenue	UNIT Annual MWH [2]	COSTS Cents/KWH	CUSTOMER Revenue	UNIT Avg Bills [3]	COSTS $/Cust/Mo
North Carolina:									
Residential	1,470,762,314	5,532,922	22.15	521,139,314	22,763,030	2.29	440,987,860	1,756,541	20.92
SGS	284,040,575	839,866	28.18	115,497,633	4,567,331	2.53	72,964,352	242,917	25.03
LGS	243,199,186	710,852	28.51	132,024,891	5,142,000	2.57	2,817,953	9,171	25.61
Lighting	106,975,988	99,012		16,629,331	691,829	2.40	19,104,315	291,039	5.47
Industrial	99,478,867	328,160	25.26	49,626,341	2,048,172	2.42	1,038,505	3,707	23.35
OPT-Small	289,838,818	855,395	28.24	208,628,723	8,149,226	2.56	5,210,155	16,808	25.83
OPT-Medium	100,192,581	302,917	27.56	79,546,046	3,162,303	2.52	104,400	355	24.51
OPT-Large	308,121,006	1,029,112	24.95	291,109,861	11,720,190	2.48	54,534	215	21.14
OPT-Transmission	26,230,695	97,001	22.53	31,690,568	1,236,620	2.56	280	4	5.83
TOTAL RETAIL	$ 2,928,840,031	9,795,237	24.92	$ 1,445,892,707	59,480,701	2.43	$ 542,282,353	2,320,757	19.47

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Carolinas, LLC

DEC Exhibit 21

Average & Excess 4CP Method

Unit Cost Report

Year: 2018

	Demand	UNIT	COSTS	Energy	UNIT	COSTS	CUSTOMER	UNIT	COSTS
	Revenue	KW [1]	$/KW/Mo	Revenue	Annual MWH [2]	Cents/KWH	Revenue	Avg Bills [3]	$/Cust/Mo
North Carolina:									
Residential	1,332,009,482	2,792,243	39.75	525,907,081	22,763,030	2.31	470,812,126	1,756,541	22.34
SGS	276,577,605	514,228	44.82	115,542,170	4,567,331	2.53	73,434,580	242,917	25.19
LGS	250,707,885	538,072	38.83	130,086,106	5,142,000	2.53	2,580,570	9,171	23.45
Lighting	101,389,973	30,895		16,673,339	691,829	2.41	19,193,311	291,039	5.50
Industrial	97,933,835	208,154	39.21	49,544,634	2,048,172	2.42	1,031,742	3,707	23.19
OPT-Small	310,564,462	732,758	35.32	203,841,391	8,149,226	2.50	4,495,679	16,808	22.29
OPT-Medium	107,787,898	262,804	34.18	77,651,324	3,162,303	2.46	90,003	355	21.13
OPT-Large	335,826,455	907,546	30.84	284,258,369	11,720,190	2.43	46,932	215	18.19
OPT-Transmission	29,433,529	88,557	27.70	30,841,138	1,236,620	2.49	268	4	5.57
TOTAL RETAIL	$ 2,842,231,124	6,075,257	38.99	$ 1,434,345,552	59,480,701	2.41	$ 571,685,211	2,320,757	20.53

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Carolinas, LLC

DEC Exhibit 22

Average & Excess Dominion Method

Unit Cost Report

Year: 2018

	Demand Revenue	UNIT KW [1]	COSTS $/KW/Mo	Energy Revenue	UNIT Annual MWH [2]	COSTS Cents/KWH	CUSTOMER Revenue	UNIT Avg Bills [3]	COSTS $/Cust/Mo
North Carolina:									
Residential	1,331,049,077	5,442,936	20.38	526,418,061	22,763,030	2.31	474,792,853	1,756,541	22.53
SGS	277,410,278	996,016	23.21	115,439,284	4,567,331	2.53	73,055,583	242,917	25.06
LGS	248,324,743	996,232	20.77	130,387,368	5,142,000	2.54	2,619,390	9,171	23.80
Lighting	107,826,621	175,397		16,519,821	691,829	2.39	18,849,174	291,039	5.40
Industrial	102,714,740	477,051	17.94	48,903,321	2,048,172	2.39	948,486	3,707	21.32
OPT-Small	301,070,552	1,264,578	19.84	205,332,682	8,149,226	2.52	4,707,659	16,808	23.34
OPT-Medium	105,631,949	471,449	18.67	77,998,181	3,162,303	2.47	92,567	355	21.73
OPT-Large	328,167,797	1,623,870	16.84	285,467,856	11,720,190	2.44	48,408	215	18.76
OPT-Transmission	28,443,730	155,431	15.25	31,018,104	1,236,620	2.51	270	4	5.63
TOTAL RETAIL	$ 2,830,639,487	11,602,960	20.33	$ 1,437,484,677	59,480,701	2.42	$ 575,114,391	2,320,757	20.65

[1] Allocation Factor: All - Production Demand

[2] Allocation Factor: All - MWHs at Meter

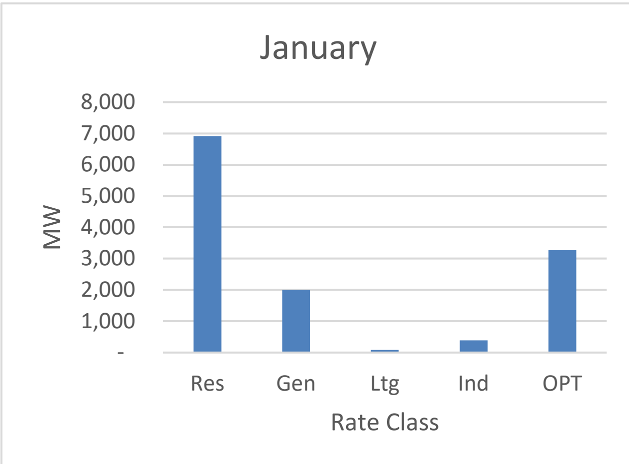
[3] Allocation Factor: All - Cust Num

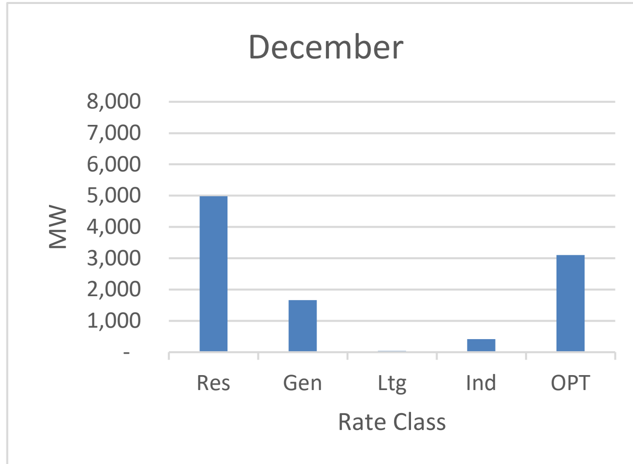
Duke Energy Carolinas, LLC **DEC Exhibit 23**

Production Demands

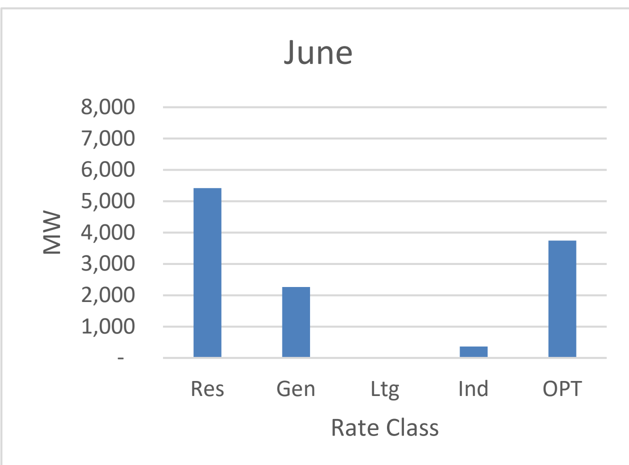
North Carolina Retail

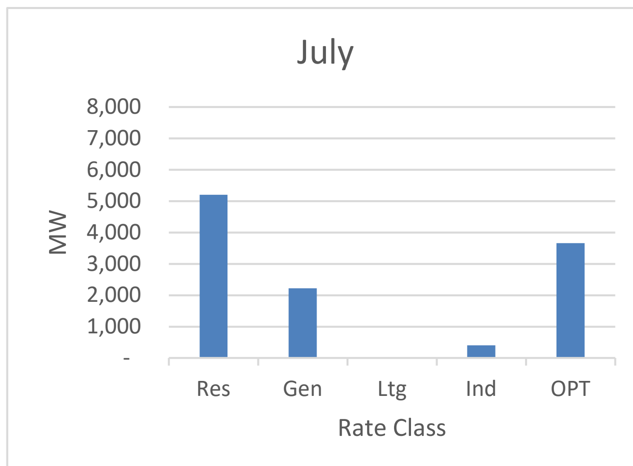
Winter Peak Months



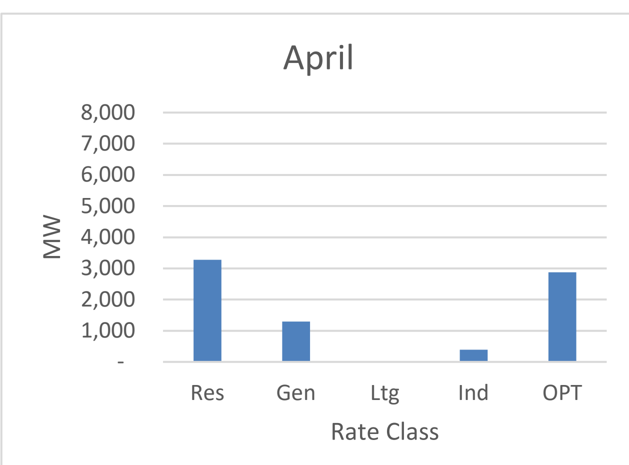


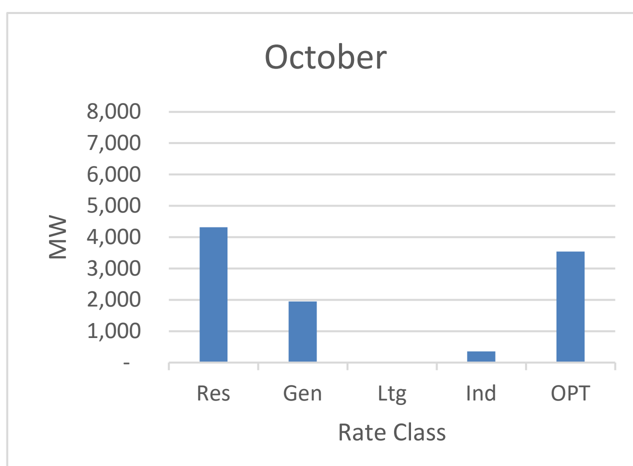
Summer Peak Months





Off Peak Months





Duke Energy Progress, LLC

DEP Exhibit 1

Production Demands (KW)

Year: 2018

	Coincident Peaks											
	January	February	March	April	May	June	July	August	September	October	November	December
North Carolina:												
Residential	5,755,959	4,338,513	3,636,141	2,439,634	3,218,023	3,850,873	3,741,128	3,700,888	3,183,980	3,117,060	3,631,160	3,793,185
SGS	536,092	339,033	395,170	236,250	389,810	477,928	480,154	430,733	483,043	491,295	353,125	342,072
MGS	1,809,014	1,244,757	1,780,871	1,322,069	1,941,993	2,187,952	2,083,819	2,111,483	2,301,785	1,928,597	1,920,826	1,797,867
SI	3,614	2,404	2,145	1,706	3,446	5,504	7,969	8,635	19,265	20,404	11,224	4,693
LGS	846,735	905,725	1,009,730	987,854	1,081,800	1,241,189	1,213,649	1,205,273	1,218,096	1,142,512	1,006,648	1,002,048
Lighting	678	464	623	504	560	566	590	601	554	536	541	563
NC Retail	8,952,091	6,830,896	6,824,679	4,988,017	6,635,632	7,764,011	7,527,308	7,457,613	7,206,721	6,700,404	6,923,524	6,940,428
NC Wholesale	4,744,742	3,181,890	3,064,984	1,999,387	2,904,497	3,617,292	3,506,689	3,518,194	3,308,381	3,047,405	3,209,152	3,150,546
Total NC	13,696,834	10,012,786	9,889,664	6,987,404	9,540,129	11,381,303	11,033,997	10,975,807	10,515,102	9,747,809	10,132,675	10,090,974
South Carolina:												
Residential	777,822	559,023	450,153	304,774	410,176	500,552	487,337	496,675	429,226	398,889	471,169	500,406
SGS	77,013	47,000	53,219	32,314	56,023	70,327	70,872	64,844	71,670	92,380	66,024	45,594
MGS	274,056	183,954	260,698	195,978	285,582	319,517	304,283	311,361	342,825	267,138	268,570	267,419
SI	4,159	1,538	1,073	856	1,966	3,033	2,552	1,625	3,544	3,989	3,779	5,814
LGS	143,886	212,943	267,500	267,608	309,470	298,421	303,362	325,016	297,416	293,580	268,511	277,504
Lighting	118	82	111	89	99	101	108	108	102	98	100	104
SC Retail	1,277,055	1,004,541	1,032,754	801,620	1,063,316	1,191,950	1,168,513	1,199,629	1,144,783	1,056,074	1,078,153	1,096,840
SC Wholesale	48,476	32,363	35,654	19,161	35,819	45,452	43,627	41,812	39,353	36,615	36,062	36,173
Total SC	1,325,530	1,036,904	1,068,408	820,781	1,099,135	1,237,402	1,212,140	1,241,441	1,184,136	1,092,688	1,114,216	1,133,013
System	15,022,364	11,049,690	10,958,072	7,808,185	10,639,264	12,618,705	12,246,137	12,217,248	11,699,238	10,840,497	11,246,891	11,223,987

Duke Energy Progress, LLC
DEP Exhibit 2

Cost of Service Analysis Results

FERC 12CP Test

For the twelve months ending December 2018

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Test Results
Annual Maximum:		11,831	12,531	12,094	12,770	12,376	14,159	15,515	13,248	14,407	15,322	
	Month	Feb	Jan	Jul	Jul	Feb	Jan	Feb	Jan	Jan	Jan	
	Month #	2	1	7	7	2	1	2	1	1	1	
Annual Minimum:		8,308	8,811	8,233	8,616	8,505	8,362	7,887	9,031	9,711	8,012	
	Month	Nov	Apr	Oct	Apr	Apr	Apr	Apr	Apr	Apr	Apr	
	Month #	11	4	10	4	4	4	4	4	4	4	
Summer Max:		11,796	12,074	12,094	12,770	12,166	12,219	12,706	13,061	12,590	12,841	
	Month	Aug	Aug	Jul	Jul	Aug	Sep	Jun	Jul	Jul	Jun	
	Month #	8	8	7	7	8	9	6	7	7	6	
Winter Max:		11,831	12,531	12,013	11,338	12,376	14,159	15,515	13,248	14,407	15,322	
	Month	Feb	Jan	Jan	Jan	Feb	Jan	Feb	Jan	Jan	Jan	
	Month #	2	1	1	1	2	1	2	1	1	1	
Test 1: ON and Off Peak Test												
Summer CP Method:												
	Summer Max	11,796	12,074	12,094	12,770	12,166	12,219	12,706	13,061	12,590	12,841	
	Annual Max	11,831	12,531	12,094	12,770	12,376	14,159	15,515	13,248	14,407	15,322	
		99.7%	96.4%	100.0%	100.0%	98.3%	86.3%	81.9%	98.6%	87.4%	83.8%	
	Avg Off-Peak	10,238	10,616	10,303	10,616	11,088	11,425	11,269	11,067	11,315	11,600	
	Annual Max	11,831	12,531	12,094	12,770	12,376	14,159	15,515	13,248	14,407	15,322	
		86.5%	84.7%	85.2%	83.1%	89.6%	80.7%	72.6%	83.5%	78.5%	75.7%	
	Difference	13.2%	11.6%	14.8%	16.9%	8.7%	5.6%	9.3%	15.1%	8.9%	8.1%	
	<= 19%	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	
	Supports 12CP?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**10 of 10**
Test 2: Low to Annual Peak Test												
	Annual Min	8,308	8,811	8,233	8,616	8,505	8,362	7,887	9,031	9,711	8,012	
	Annual Max	11,831	12,531	12,094	12,770	12,376	14,159	15,515	13,248	14,407	15,322	
		70.2%	70.3%	68.1%	67.5%	68.7%	59.1%	50.8%	68.2%	67.4%	52.3%	
	>= 66%	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes	No	
	Supports 12CP?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**No**	**Yes**	**Yes**	**No**	**7 of 10**
Test 3: Average to Annual Peak Test												
	12CP Average	10,368	10,738	10,453	10,795	11,178	11,491	11,389	11,233	11,421	11,704	
	Annual Max	11,831	12,531	12,094	12,770	12,376	14,159	15,515	13,248	14,407	15,322	
		87.6%	85.7%	86.4%	84.5%	90.3%	81.2%	73.4%	84.8%	79.3%	76.4%	
	>= 81%	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	No	No	
	Supports 12CP?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**	**No**	**No**	**7 of 10**

From FERC Opinion 501 - Docket Nos. EL05-19-002 and ER05-168-001 - Golden Spread EMC - April 2008

Duke Energy Progress, LLC

DEP Exhibit 3

Peak Responsibility Methods (KW) - Non-Firm

Year: 2018

	June Summer 1CP-Sum	January Winter 1CP-Win	January November June July 4CP	12CP
North Carolina:				
Residential	3,850,873	5,755,959	4,244,780	3,700,545
SGS	477,928	536,092	461,825	412,892
MGS	2,187,952	1,809,014	2,000,403	1,869,253
SI	5,504	3,614	7,078	7,584
LGS	1,241,189	846,735	1,077,055	1,071,772
Lighting	566	678	594	565
NC Retail	7,764,011	8,952,091	7,791,734	7,062,610
NC Wholesale	3,617,292	4,744,742	3,769,469	3,271,097
Total NC	11,381,303	13,696,834	11,561,202	10,333,707
Per Docket E-2 Sub 1219	11,381,303	13,696,834	11,561,202	10,333,707
South Carolina:				
Residential	500,552	777,822	559,220	482,184
SGS	70,327	77,013	71,059	62,273
MGS	319,517	274,056	291,606	273,448
SI	3,033	4,159	3,381	2,827
LGS	298,421	143,886	253,545	272,101
Lighting	101	118	107	102
SC Retail	1,191,950	1,277,055	1,178,918	1,092,936
SC Wholesale	45,452	48,476	43,404	37,547
Total SC	1,237,402	1,325,530	1,222,322	1,130,483
Per Docket E-2 Sub 1219	1,237,402	1,325,530	1,222,322	1,130,483
System	12,618,705	15,022,364	12,783,524	11,464,190

Duke Energy Progress, LLC

DEP Exhibit 4

Summer/Winter Peak & Average Allocation Method

Year: 2018

Rate Schedule	E1 Prod Out. Level kWh	Ratio of Each Rate Schedule To Total	Col.(3) x Energy Weighting Factor	June Summer CP Demand (KW)	Ratio of Each Rate Schedule To Total	Col.(6) x Demand Weighting Factor	January Winter CP Demand (KW)	Ratio of Each Rate Schedule To Total	Col.(9) x Demand Weighting Factor	S/W P&A Allocation Factors
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
North Carolina:										
Residential	17,416,906,173	0.264097	0.143861	3,850,873	0.305172	0.069468	5,755,959	0.383159	0.087221	30.0550%
SGS	2,071,898,933	0.031417	0.017114	477,928	0.037875	0.008622	536,092	0.035686	0.008124	3.3859%
MGS	11,663,352,961	0.176855	0.096337	2,187,952	0.173390	0.039470	1,809,014	0.120421	0.027412	16.3220%
SI	44,807,202	0.000679	0.000370	5,504	0.000436	0.000099	3,614	0.000241	0.000055	0.0524%
LGS	8,728,935,826	0.132359	0.072100	1,241,189	0.098361	0.022391	846,735	0.056365	0.012831	10.7321%
Lighting	374,947,587	0.005685	0.003097	566	0.000045	0.000010	678	0.000045	0.000010	0.3117%
NC Retail	40,300,848,683	0.611093	0.332878	7,764,011	0.615278	0.140060	8,952,091	0.595918	0.135653	60.8591%
NC Wholesale	18,682,169,387	0.283283	0.154312	3,617,292	0.286661	0.065255	4,744,742	0.315845	0.071898	29.1464%
Total NC	58,983,018,069	0.894376	0.487190	11,381,303	0.901939	0.205315	13,696,834	0.911763	0.207551	90.0056%
South Carolina:										
Residential	2,288,678,709	0.034704	0.018904	500,552	0.039667	0.009030	777,822	0.051778	0.011787	3.9720%
SGS	296,123,138	0.004490	0.002446	70,327	0.005573	0.001269	77,013	0.005127	0.001167	0.4882%
MGS	1,724,140,413	0.026144	0.014241	319,517	0.025321	0.005764	274,056	0.018243	0.004153	2.4158%
SI	19,221,900	0.000291	0.000159	3,033	0.000240	0.000055	4,159	0.000277	0.000063	0.0276%
LGS	2,348,530,475	0.035611	0.019398	298,421	0.023649	0.005383	143,886	0.009578	0.002180	2.6962%
Lighting	84,386,208	0.001280	0.000697	101	0.000008	0.000002	118	0.000008	0.000002	0.0701%
SC Retail	6,761,080,842	0.102520	0.055845	1,191,950	0.094459	0.021502	1,277,055	0.085010	0.019351	9.6699%
SC Wholesale	204,676,844	0.003104	0.001691	45,452	0.003602	0.000820	48,476	0.003227	0.000735	0.3245%
Total SC	6,965,757,686	0.105624	0.057536	1,237,402	0.098061	0.022322	1,325,530	0.088237	0.020086	9.9944%
SYSTEM	65,948,775,755	1.000000	0.544726	12,618,705	1.000000	0.227637	15,022,364	1.000000	0.227637	100.0000%

Note 1: Excludes NCEMC Peaking Capacity

Calculation of Load Factor for SWP&A Weights:

Summer Peak - Col (5)	12,618,705
Winter Peak - Col (8)	15,022,364
Average for LF Calc	13,820,535
Total E1 mWh - Col (2)	65,948,776
Test Year Hours	8,760
Load Factor (Energy Wgt)	54.4726%
Peaks @ (1-LF)/2 each	22.7637%

Duke Energy Progress, LLC

DEP Exhibit 5

Average & Excess Demand Allocation Method

Year: 2018

	Inputs			Calculation						
	Summer Coin. Peak June	MWH @ Gen	NCD (kW)	Average Demand (KW)	Class Load Factor	Excess Demand (Hourly kW)	Average Demand Component (KW)	Excess Demand Component (KW)	Average & Excess Demand	Average & Excess Hourly Demand Ratio
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
North Carolina:										
Residential	3,850,873	17,416,906	10,833,545	1,988,231	51.63%	8,845,314	1,186,191	3,568,144	4,754,335	41.70%
SGS	477,928	2,071,899	1,017,156	236,518	49.49%	780,638	141,108	314,905	456,013	4.00%
MGS	2,187,952	11,663,353	3,248,999	1,331,433	60.85%	1,917,566	794,341	773,534	1,567,875	13.75%
SI	5,504	44,807	104,121	5,115	92.93%	99,006	3,052	39,938	42,990	0.38%
LGS	1,241,189	8,728,936	1,368,665	996,454	80.28%	372,211	594,491	150,147	744,638	6.53%
Lighting	566	374,948	104,059	42,802	7568.75%	61,256	25,536	24,710	50,247	0.44%
NC Retail	7,764,011	40,300,849	16,676,545	4,600,554	59.25%	12,075,991	2,744,719	4,871,379	7,616,098	66.80%
NC Wholesale	3,617,292	18,682,169	5,369,000	2,132,668	58.96%	3,236,332	1,272,363	1,305,516	2,577,879	22.61%
Total NC	11,381,303	58,983,018	22,045,545	6,733,221	59.16%	15,312,324	4,017,082	6,176,895	10,193,977	89.41%
South Carolina:										
Residential	500,552	2,288,679	1,463,974	261,265	52.20%	1,202,710	155,872	485,165	641,038	5.62%
SGS	70,327	296,123	170,870	33,804	48.07%	137,066	20,168	55,291	75,459	0.66%
MGS	319,517	1,724,140	487,989	196,820	61.60%	291,170	117,424	117,456	234,880	2.06%
SI	3,033	19,222	23,680	2,194	72.36%	21,486	1,309	8,667	9,976	0.09%
LGS	298,421	2,348,530	391,354	268,097	89.84%	123,257	159,948	49,721	209,670	1.84%
Lighting	101	84,386	22,536	9,633	9544.88%	12,903	5,747	5,205	10,952	0.10%
SC Retail	1,191,950	6,761,081	2,560,403	771,813	64.75%	1,788,590	460,468	721,506	1,181,974	10.37%
SC Wholesale	45,452	204,677	51,000	23,365	51.41%	27,635	13,940	11,148	25,087	0.22%
Total SC	1,237,402	6,965,758	2,611,403	795,178	64.26%	1,816,225	474,408	732,654	1,207,062	10.59%
SYSTEM	12,618,705	65,948,776	24,656,948	7,528,399	59.66%	17,128,549	4,491,490	6,909,548	11,401,039	100.00%

Hours in Year: 8,760

System Load Factor: 59.6606% = (65,948,776,000 / 12,618,705) / 8,760

column(4)=column(2)/8760

column(5)=column(4)/column(1)

column(6)=column(3)-column(4)

column(7)=(column(4)/(column(4) Total))xLoad Factor

column(8)=(column(6)/(column(6) Total))x(1-Load Factor)

column(9)=column(7)+column(8)

column(10)=column(9)*column(10) Total

Duke Energy Progress, LLC

DEP Exhibit 6

Average & Excess 4CP Demand Allocation Method

Year: 2018

	Inputs			Calculation						
	Summer Coin. Peak June	MWH @ Gen	4CP (kW)	Average Demand (KW)	Class Load Factor	Excess Demand (Hourly kW)	Average Demand Component (KW)	Excess Demand Component (KW)	Average & Excess Demand	Average & Excess Hourly Demand Ratio
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
North Carolina:										
Residential	3,850,873	17,416,906	4,244,780	1,988,231	51.63%	2,256,548	1,186,191	910,277	2,096,469	31.71%
SGS	477,928	2,071,899	461,825	236,518	49.49%	225,306	141,108	90,887	231,995	3.51%
MGS	2,187,952	11,663,353	2,000,403	1,331,433	60.85%	668,970	794,341	269,858	1,064,200	16.10%
SI	5,504	44,807	7,078	5,115	92.93%	1,963	3,052	792	3,843	0.06%
LGS	1,241,189	8,728,936	1,077,055	996,454	80.28%	80,601	594,491	32,514	627,005	9.48%
Lighting	566	374,948	594	42,802	7568.75%	-42,208	25,536	-17,027	8,509	0.13%
NC Retail	7,764,011	40,300,849	7,791,734	4,600,554	59.25%	3,191,180	2,744,719	1,287,302	4,032,021	60.99%
NC Wholesale	3,617,292	18,682,169	3,769,469	2,132,668	58.96%	1,636,801	1,272,363	660,275	1,932,638	29.23%
Total NC	11,381,303	58,983,018	11,561,202	6,733,221	59.16%	4,827,981	4,017,082	1,947,577	5,964,659	90.22%
South Carolina:										
Residential	500,552	2,288,679	559,220	261,265	52.20%	297,955	155,872	120,193	276,066	4.18%
SGS	70,327	296,123	71,059	33,804	48.07%	37,255	20,168	15,028	35,196	0.53%
MGS	319,517	1,724,140	291,606	196,820	61.60%	94,787	117,424	38,236	155,660	2.35%
SI	3,033	19,222	3,381	2,194	72.36%	1,186	1,309	479	1,788	0.03%
LGS	298,421	2,348,530	253,545	268,097	89.84%	-14,552	159,948	-5,870	154,078	2.33%
Lighting	101	84,386	107	9,633	9544.88%	-9,527	5,747	-3,843	1,904	0.03%
SC Retail	1,191,950	6,761,081	1,178,918	771,813	64.75%	407,105	460,468	164,224	624,692	9.45%
SC Wholesale	45,452	204,677	43,404	23,365	51.41%	20,039	13,940	8,084	22,023	0.33%
Total SC	1,237,402	6,965,758	1,222,322	795,178	64.26%	427,144	474,408	172,307	646,715	9.78%
SYSTEM	12,618,705	65,948,776	12,783,524	7,528,399	59.66%	5,255,125	4,491,490	2,119,884	6,611,375	100.00%

Hours in Year: 8,760

System Load Factor: 59.6606% = (65,948,776,000 / 12,618,705) / 8,760

column(4)=column(2)/8760

column(5)=column(4)/column(1)

column(6)=column(3)-column(4)

column(7)=(column(4)/(column(4) Total))xLoad Factor

column(8)=(column(6)/(column(6) Total))x(1-Load Factor)

column(9)=column(7)+column(8)

column(10)=column(9)*column(10) Total

Duke Energy Progress, LLC

DEP Exhibit 7

Average & Excess Demand Allocation - Dominion Method

Year: 2018

	Inputs			Calculation						
	Summer Coin. Peak June	MWH @ Gen	Diversified NCD (kW)	Average Demand (KW)	System Peak Less Avg Dmnd	Excess = NCD Less Avg Dmnd (kW)	Ratio (%)	Allocation of Excess (KW)	Average & Excess Demand (KW)	Average & Excess Demand Ratio
	(1)	(2)	(3)	(4)=(2)/ 8,760	(5)=(1)-(4)	(6)=(3)-(4)	(7)=(5)/(6)	(8)=(6)x 64.99%	(9)=(4)+(8)	(10)
North Carolina:										
Residential	3,850,873	17,416,906	4,338,514	1,988,231		2,350,282		1,527,449	3,515,681	27.86%
SGS	477,928	2,071,899	491,645	236,518		255,127		165,807	402,325	3.19%
MGS	2,187,952	11,663,353	2,449,019	1,331,433		1,117,586		726,320	2,057,753	16.31%
SI	5,504	44,807	47,975	5,115		42,860		27,855	32,970	0.26%
LGS	1,241,189	8,728,936	1,289,349	996,454		292,895		190,353	1,186,807	9.41%
Lighting	566	374,948	100,703	42,802		57,901		37,630	80,432	0.64%
NC Retail	7,764,011	40,300,849	8,717,206	4,600,554		4,116,652		2,675,414	7,275,967	57.66%
NC Wholesale	3,617,292	18,682,169	5,161,000	2,132,668		3,028,332		1,968,114	4,100,782	32.50%
Total NC	11,381,303	58,983,018	13,878,206	6,733,221		7,144,985		4,643,528	11,376,749	90.16%
South Carolina:										
Residential	500,552	2,288,679	559,023	261,265		297,758		193,513	454,778	3.60%
SGS	70,327	296,123	92,438	33,804		58,634		38,106	71,910	0.57%
MGS	319,517	1,724,140	364,790	196,820		167,970		109,164	305,983	2.42%
SI	3,033	19,222	9,379	2,194		7,185		4,669	6,864	0.05%
LGS	298,421	2,348,530	383,911	268,097		115,813		75,267	343,364	2.72%
Lighting	101	84,386	22,093	9,633		12,460		8,098	17,731	0.14%
SC Retail	1,191,950	6,761,081	1,431,633	771,813		659,821		428,818	1,200,631	9.51%
SC Wholesale	45,452	204,677	51,000	23,365		27,635		17,960	41,325	0.33%
Total SC	1,237,402	6,965,758	1,482,633	795,178		687,456		446,778	1,241,956	9.84%
SYSTEM	12,618,705	65,948,776	15,360,839	7,528,399	5,090,306	7,832,440	64.99%	5,090,306	12,618,705	100.00%
									12,618,705	

Hours in Year: 8,760

System Load Factor: 59.6606% = (65,948,776,000 / 12,618,705) / 8,760

Duke Energy Progress, LLC

DEP Exhibit 8

Base, Intermediate & Peak Allocation Method

Year: 2018

Generating Plant	Fuel Type	Capacity MW	Average Fuel Cost $/kWh	Net mWh	Annual Capacity Factor	Gross Plant $	Pct Energy	Gross Investment Energy	Gross Investment Demand
Base Load Units:									
Robinson	Nuclear	741	7.11	5,276,118	81.3%	1,641,168,860	100%	1,641,168,860	-
Brunswick	Nuclear	1,870	6.51	14,626,967	89.3%	3,083,781,826	100%	3,083,781,826	-
Harris	Nuclear	932	6.77	7,587,914	92.9%	4,187,436,155	100%	4,187,436,155	-
HF Lee	Gas Turbine/CC	888	34.16	7,210,666	92.7%	695,299,706	100%	695,299,706	-
Smith Energy	Gas Turbine/CC	1,073	29.19	8,821,723	93.9%	761,984,596	100%	761,984,596	-
Sutton	Gas Turbine/CC	607	42.63	3,424,568	64.4%	541,123,187	100%	541,123,187	-
Total Base Load Units		6,111		46,947,956		10,910,794,329		10,910,794,329	-
Intermediate Units:									
Asheville	Coal	378	39.93	1,237,903	37.4%	467,059,817	37.4%	174,607,629	292,452,188
Mayo	Coal	727	41.62	1,491,333	23.4%	1,215,045,064	23.4%	284,530,283	930,514,781
Roxboro	Coal	2,439	34.90	5,927,599	27.7%	2,333,238,869	27.7%	647,324,601	1,685,914,268
Smith Energy	Gas Turbine	772	47.81	3,073,958	45.5%	289,995,526	45.5%	131,815,906	158,179,619
Sutton	Gas Turbine	78	45.73	218,887	32.0%	100,187,704	32.0%	32,094,875	68,092,829
Total Intermediate Units		4,394		11,949,680		4,405,526,980		1,270,373,294	3,135,153,686
Peaking Units:									
Asheville	Gas Turbine	320	57.65	506,865	18.1%	114,191,604	0.0%	-	114,191,604
Blewett	Gas Turbine	52		199	0.0%	13,460,860	0.0%	-	13,460,860
Darlington	Gas Turbine	664	112.94	230,819	4.0%	129,888,403	0.0%	-	129,888,403
Wayne	Gas Turbine	857	79.17	458,014	6.1%	275,074,172	0.0%	-	275,074,172
Weatherspoon	Gas Turbine	124	440.49	1,712	0.2%	23,763,288	0.0%	-	23,763,288
Total Peaking Units		2,017		1,197,609		556,378,327		-	556,378,327
Hydro Units:									
Blewett	Storage	27		88,367	37.4%	38,202,535	50.0%	19,101,267	19,101,267
Marshall	Storage	4		812	2.3%	13,497,283	50.0%	6,748,642	6,748,642
Tillery	Storage	84		238,608	32.4%	33,822,515	50.0%	16,911,257	16,911,257
Walters	Storage	112		477,853	48.7%	58,194,566	50.0%	29,097,283	29,097,283
Total Hydro Units		227		805,640		143,716,899		71,858,449	71,858,449
Solar Units:									
Warsaw		22.75		112,927	56.7%	84,436,980	56.7%	47,845,927	36,591,053
Fayetteville		8.09		23,122	32.6%	31,564,234	32.6%	10,304,728	21,259,506
Camp Lejeune		4.48		19,769	50.4%	17,891,334	50.4%	9,012,501	8,878,833
Elm City		14.00		79,375	64.7%	49,603,093	64.7%	32,104,089	17,499,004
Total Renewable Units		49.3		235,193		183,495,640		99,267,245	84,228,396
Total System		12,798		61,136,078		16,199,912,175		12,352,293,317	3,847,618,858
Percent of Total								76.2%	23.8%

Duke Energy Progress, LLC
Base, Intermediate & Peak

DEP Exhibit 9

Year: 2018

Plant-in-Service		Factor	Total Company	NCRES	NCRET	NCSGS	NCSGSTCLR	NCSGTM	NCMGS	NCSI	NCLGS
Base	Energy	Energy	10,910,794,329	2,793,822,085	87,691,316	337,316,108	5,466,042	1,444,760,786	484,864,804	7,413,059	195,630,465
	Demand	SCP	0	0	0	0	0	0	0	0	0
	Total		10,910,794,329	2,793,822,085	87,691,316	337,316,108	5,466,042	1,444,760,786	484,864,804	7,413,059	195,630,465
Intermediate	Energy	Energy	1,270,373,294	325,292,262	10,210,137	39,274,627	636,426	168,217,406	56,454,121	863,123	22,777,784
	Demand	12CP	3,135,153,686	984,376,370	27,625,185	111,887,131	1,027,962	355,030,238	156,161,104	2,074,013	42,431,719
	Total		4,405,526,980	1,309,668,632	37,835,322	151,161,758	1,664,388	523,247,644	212,615,225	2,937,135	65,209,503
Peaking	Energy	Energy	0	0	0	0	0	0	0	0	0
	Demand	SCP	556,378,327	165,349,728	4,441,239	20,900,577	172,020	67,647,137	28,823,081	242,675	8,112,443
	Total		556,378,327	165,349,728	4,441,239	20,900,577	172,020	67,647,137	28,823,081	242,675	8,112,443
Storage	Energy	Energy	71,858,449	18,400,101	577,535	2,221,563	35,999	9,515,189	3,193,318	48,822	1,288,421
	Demand	SCP	71,858,449	21,355,568	573,603	2,699,392	22,217	8,736,894	3,722,614	31,342	1,047,754
	Total		143,716,899	39,755,669	1,151,138	4,920,954	58,216	18,252,083	6,915,932	80,165	2,336,175
Solar	Energy	Energy	99,267,245	25,418,408	797,822	3,068,928	49,730	13,144,545	4,411,337	67,445	1,779,861
	Demand	12CP	84,228,396	26,446,054	742,173	3,005,937	27,617	9,538,170	4,195,392	55,720	1,139,962
	Total		183,495,640	51,864,461	1,539,995	6,074,865	77,347	22,682,714	8,606,729	123,165	2,919,823
Total			16,199,912,175	4,360,460,575	132,659,009	520,374,261	7,438,014	2,076,590,364	741,825,772	10,796,198	274,208,410
Check:											
Plant_BIP_Composite_Factor ==>			100.0000%	26.9166%	0.8189%	3.2122%	0.0459%	12.8185%	4.5792%	0.0666%	1.6927%

Duke Energy Progress, LLC
Cost of Service Analysis Results
Production Demand Allocation Factors
For the twelve months ending December 2018

DEP Exhibit 10

		Peak Responsibility Methods				Energy Weighting Methods				Time Differentiated Method
		Summer	Winter							
	Load	1 CP	1 CP	4CP	12CP	SWPA	A&E	A&E 4CP	A&E Dom	BIP
	Factor	Exhibit3	Exhibit3	Exhibit3	Exhibit3	Exhibit4	Exhibit5	Exhibit6	Exhibit7	Exhibit8
North Carolina:										
Residential	51.63%	30.5172%	38.3159%	33.2051%	32.2792%	30.0550%	41.7009%	31.7100%	27.8609%	27.7355%
SGS	49.49%	3.7875%	3.5686%	3.6127%	3.6016%	3.3859%	3.9997%	3.5090%	3.1883%	3.2581%
MGS	60.85%	17.3390%	12.0421%	15.6483%	16.3051%	16.3220%	13.7520%	16.0965%	16.3072%	17.3977%
SI	92.93%	0.0436%	0.0241%	0.0554%	0.0662%	0.0524%	0.3771%	0.0581%	0.2613%	0.0666%
LGS	80.28%	9.8361%	5.6365%	8.4253%	9.3489%	10.7321%	6.5313%	9.4837%	9.4051%	12.3316%
Lighting		0.0045%	0.0045%	0.0046%	0.0049%	0.3117%	0.4407%	0.1287%	0.6374%	0.4347%
NC Retail	59.25%	61.5278%	59.5918%	60.9514%	61.6058%	60.8591%	66.8018%	60.9861%	57.6602%	61.2242%
NC Wholesale	58.96%	28.6661%	31.5845%	29.4869%	28.5332%	29.1464%	22.6109%	29.2320%	32.4976%	28.3821%
Total NC	59.16%	90.1939%	91.1763%	90.4383%	90.1390%	90.0056%	89.4127%	90.2181%	90.1578%	89.6063%
South Carolina:										
Residential	52.20%	3.9667%	5.1778%	4.3745%	4.2060%	3.9720%	5.6226%	4.1756%	3.6040%	3.6358%
SGS	48.07%	0.5573%	0.5127%	0.5559%	0.5432%	0.4882%	0.6619%	0.5324%	0.5699%	0.4719%
MGS	61.60%	2.5321%	1.8243%	2.2811%	2.3852%	2.4158%	2.0602%	2.3544%	2.4248%	2.5656%
SI	72.36%	0.0240%	0.0277%	0.0264%	0.0247%	0.0276%	0.0875%	0.0270%	0.0544%	0.0281%
LGS	89.84%	2.3649%	0.9578%	1.9834%	2.3735%	2.6962%	1.8390%	2.3305%	2.7211%	3.2787%
Lighting		0.0008%	0.0008%	0.0008%	0.0009%	0.0701%	0.0961%	0.0288%	0.1405%	0.0978%
SC Retail	64.75%	9.4459%	8.5010%	9.2222%	9.5335%	9.6699%	10.3673%	9.4487%	9.5147%	10.0780%
SC Wholesale	51.41%	0.3602%	0.3227%	0.3395%	0.3275%	0.3245%	0.2200%	0.3331%	0.3275%	0.3157%
Total SC	64.26%	9.8061%	8.8237%	9.5617%	9.8610%	9.9944%	10.5873%	9.7819%	9.8422%	10.3937%
System		100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

Duke Energy Progress, Inc.

DEP Exhibit 11

Cost of Service Analysis Results
ROR At Present Rates
For the twelve months ending December 2018

		Peak Responsibility Methods				Energy Weighting Methods				Time Differentiated Method	
	Load Factor	Summer 1 CP	Winter 1 CP	4CP	12CP	SWPA	A&E	A&E 4CP	A&E Dom	BIP	Average of Returns
North Carolina:											
Residential	51.63%	4.48%	2.77%	3.84%	4.06%	4.47%	2.33%	4.23%	5.12%	5.12%	4.05%
SGS	49.49%	4.90%	5.39%	5.29%	5.31%	5.73%	4.48%	5.44%	6.14%	5.96%	5.41%
MGS	60.85%	4.41%	8.71%	5.55%	5.09%	5.21%	6.62%	5.13%	5.03%	4.38%	5.57%
SI	92.93%	4.93%	7.16%	3.86%	2.99%	4.31%	-5.42%	3.76%	-3.78%	3.15%	2.33%
LGS	80.28%	5.16%	12.92%	7.10%	5.78%	4.53%	9.60%	5.55%	5.67%	2.87%	6.58%
Lighting		8.84%	8.85%	8.84%	8.84%	7.65%	7.17%	8.34%	6.54%	7.21%	8.03%
NC Retail		4.74%	5.03%	4.83%	4.73%	4.84%	4.08%	4.81%	5.26%	4.78%	4.79%
South Carolina:											
Residential	52.20%	6.14%	3.61%	5.20%	5.59%	5.98%	3.18%	5.70%	6.96%	6.93%	5.48%
SGS	48.07%	6.03%	6.73%	6.04%	6.27%	7.14%	4.69%	6.40%	5.85%	7.39%	6.28%
MGS	61.60%	11.38%	17.67%	13.27%	12.48%	12.45%	14.89%	12.54%	12.06%	11.23%	13.11%
SI	72.36%	18.25%	15.92%	16.71%	17.85%	16.18%	1.77%	16.60%	7.17%	16.17%	14.07%
LGS	89.84%	5.76%	22.46%	8.37%	5.72%	4.51%	9.18%	5.94%	4.04%	1.95%	7.55%
Lighting		10.31%	10.23%	10.29%	10.31%	8.28%	7.67%	9.43%	6.55%	7.60%	8.96%
SC Retail		7.40%	8.60%	7.67%	7.30%	7.22%	6.48%	7.39%	7.31%	6.75%	7.35%

Duke Energy Progress, Inc.
Cost of Service Analysis Results
ROR At Present Rates Index
For the twelve months ending December 2018

DEP Exhibit 12

	Load Factor	Peak Responsibility Methods: Summer 1 CP	Winter 1 CP	4CP	12CP	Energy Weighting Methods: SWPA	A&E	A&E 4CP	A&E Dom	Time Differentiated Method: BIP
North Carolina:										
Residential	51.63%	94.58%	55.15%	79.66%	85.76%	92.33%	57.08%	87.88%	97.22%	107.17%
SGS	49.49%	103.36%	107.26%	109.56%	112.24%	118.25%	109.76%	113.16%	116.65%	124.74%
MGS	60.85%	93.04%	173.27%	115.03%	107.52%	107.66%	162.15%	106.57%	95.59%	91.65%
SI	92.93%	103.98%	142.41%	79.89%	63.29%	88.92%	-132.81%	78.20%	-71.75%	65.92%
LGS	80.28%	108.82%	256.99%	147.17%	122.14%	93.63%	235.24%	115.32%	107.72%	60.03%
Lighting		186.55%	176.02%	183.27%	186.82%	157.93%	175.63%	173.40%	124.27%	150.78%
NC Retail		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
South Carolina:										
Residential	52.20%	83.06%	42.04%	67.83%	76.61%	82.92%	49.09%	77.12%	95.20%	102.64%
SGS	48.07%	81.54%	78.28%	78.83%	85.91%	98.88%	72.34%	86.54%	79.96%	109.51%
MGS	61.60%	153.89%	205.51%	173.14%	171.00%	172.52%	229.57%	169.65%	164.91%	166.37%
SI	72.36%	246.66%	185.18%	217.93%	244.67%	224.21%	27.37%	224.52%	97.99%	239.56%
LGS	89.84%	77.86%	261.24%	109.16%	78.32%	62.46%	141.57%	80.38%	55.21%	28.95%
Lighting		139.35%	119.01%	134.16%	141.33%	114.77%	118.33%	127.62%	89.55%	112.61%
SC Retail		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Duke Energy Progress, LLC

DEP Exhibit 13

Allocation of Fuel

Year: 2018

Intermediate Method: 12CP   Peak Method: 1CP-Sum

Rate Class	Base: Sales at Gen kWh	Base: Average Annual Hourly Demand KW	Base: Base Period Ratio 70.48%	Base: Base as % of Total	Intermediate: 12 CP Demand KW	Intermediate: Demand Peak Ratio 24.24%	Intermediate: Intermediate as % of Total	Peak: 1CP-Sum Peak Demand KW	Peak: Demand Ratio 5.28%	Peak: Peak as % of Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
North Carolina:										
Residential	17,416,906,173	1,988,231	1,401,357	26.4097%	3,700,545	896,846	32.2792%	3,850,873	203,399	30.5172%
SGS	2,071,898,933	236,518	166,704	3.1417%	412,892	100,067	3.6016%	477,928	25,244	3.7875%
MGS	11,663,352,961	1,331,433	938,428	17.6855%	1,869,253	453,023	16.3051%	2,187,952	115,565	17.3390%
SI	44,807,202	5,115	3,605	0.0679%	7,584	1,838	0.0662%	5,504	291	0.0436%
LGS	8,728,935,826	996,454	702,326	13.2359%	1,071,772	259,749	9.3489%	1,241,189	65,558	9.8361%
Lighting	374,947,587	42,802	30,168	0.5685%	565	137	0.0049%	566	30	0.0045%
NC Retail	40,300,848,683	4,600,554	3,242,589	61.1093%	7,062,610	1,711,660	61.6058%	7,764,011	410,087	61.5278%
NC Wholesale	18,682,169,387	2,132,668	1,503,159	28.3283%	3,271,097	792,767	28.5332%	3,617,292	191,061	28.6661%
Total NC	58,983,018,069	6,733,221	4,745,749	89.4376%	10,333,707	2,504,428	90.1390%	11,381,303	601,148	90.1939%
South Carolina:										
Residential	2,288,678,709	261,265	184,146	3.4704%	482,184	116,860	4.2060%	500,552	26,439	3.9667%
SGS	296,123,138	33,804	23,826	0.4490%	62,273	15,092	0.5432%	70,327	3,715	0.5573%
MGS	1,724,140,413	196,820	138,724	2.6144%	273,448	66,272	2.3852%	319,517	16,877	2.5321%
SI	19,221,900	2,194	1,547	0.0291%	2,827	685	0.0247%	3,033	160	0.0240%
LGS	2,348,530,475	268,097	188,962	3.5611%	272,101	65,945	2.3735%	298,421	15,762	2.3649%
Lighting	84,386,208	9,633	6,790	0.1280%	102	25	0.0009%	101	5	0.0008%
SC Retail	6,761,080,842	771,813	543,994	10.2520%	1,092,936	264,879	9.5335%	1,191,950	62,958	9.4459%
SC Wholesale	204,676,844	23,365	16,468	0.3104%	37,547	9,100	0.3275%	45,452	2,401	0.3602%
Total SC	6,965,757,686	795,178	560,462	10.5624%	1,130,483	273,978	9.8610%	1,237,402	65,358	9.8061%
SYSTEM	65,948,775,755	7,528,399	5,306,210	100.0000%	11,464,190	2,778,406	100.0000%	12,618,705	666,506	100.0000%

Hours in Year: 8,760

column(2) - values are from DataNonFirm worksheet

column(3)=column(2) / 8,760

column(4)=column(3) x 70.48%

column(5)=column(4) / 5,306,210

Column(6) - values are from DEP Exhibit 3

column(7)=column(6) x 24.24%

column(8)=column(7) / 2,778,406

column(9) - values are from DEP Exhibit 3

column(10)=column(9) x 5.28%

column(11)=column(10) / 666,506

$000	Plnt-in-Svc	Accum Depr	Net Plant	Ratio
Base	10,910,794	(4,224,151)	6,686,644	70.48%
Intermediate	4,497,544	(2,198,334)	2,299,210	24.24%
Peak	791,574	(290,484)	501,090	5.28%
	16,199,912	(6,712,968)	9,486,944	100.00%

Duke Energy Progress, LLC **DEP Exhibit 13**
Allocation of Fuel Pg 2 of 2
Year: 2018

Generation Fuel	1,401,869,034
Purchased Power Fuel	203,772,134
	1,605,641,168

Rate	Base Fuel	Intermediate Fuel	Peak Fuel	Total	Average Fuel ($/kWh)	Increase (Decrease) Over Average
Class	669,623,378	828,366,874	107,650,916	1,605,641,168	0.02435	
(1)	669,623,378 x (5)	828,366,874 x (8)	107,650,916 x (11)	(15)	(16)	(17)=(15)-(16)
North Carolina:						
Residential	176,845,854	267,389,943	32,852,022	477,087,819	424,045,803	53,042,015
SGS	21,037,418	29,834,302	4,077,233	54,948,954	50,444,094	4,504,860
MGS	118,426,062	135,066,417	18,665,550	272,158,029	283,965,236	-11,807,208
SI	454,958	547,993	46,954	1,049,906	1,090,912	-41,006
LGS	88,630,902	77,442,895	10,588,655	176,662,452	212,521,591	-35,859,139
Lighting	3,807,101	40,816	4,824	3,852,742	9,128,771	-5,276,029
NC Retail	409,202,296	510,322,366	66,235,239	985,759,900	981,196,406	4,563,494
NC Wholesale	189,692,943	236,359,318	30,859,329	456,911,590	454,850,904	2,060,686
Total NC	598,895,239	746,681,684	97,094,568	1,442,671,490	1,436,047,310	6,624,180
South Carolina:						
Residential	23,238,532	34,841,089	4,270,240	62,349,861	55,721,986	6,627,875
SGS	3,006,742	4,499,682	599,967	8,106,391	7,209,649	896,742
MGS	17,506,386	19,758,537	2,725,814	39,990,737	41,977,289	-1,986,552
SI	195,173	204,299	25,871	425,344	467,992	-42,648
LGS	23,846,249	19,661,206	2,545,845	46,053,300	57,179,184	-11,125,884
Lighting	856,831	7,344	861	865,036	2,054,534	-1,189,497
SC Retail	68,649,914	78,972,156	10,168,598	157,790,668	164,610,633	-6,819,965
SC Wholesale	2,078,225	2,713,035	387,750	5,179,010	4,983,225	195,785
Total SC	70,728,139	81,685,191	10,556,348	162,969,678	169,593,858	-6,624,180
SYSTEM	669,623,378	828,366,874	107,650,916	1,605,641,168	1,605,641,168	0

Duke Energy Progress, Inc.

DEP Exhibit 14
Pg 1 of 2

Cost of Service Analysis Results
ROR At Present Rates - After Fuel Adjustment
For the twelve months ending December 2018

	After Fuel Adjustment								
	Peak Responsibility Methods				Energy Weighting Methods				Time Differentiated Method
	Summer 1 CP	Winter 1 CP	4CP	12CP	SWPA	A&E	A&E 4CP	A&E Dom	BIP
North Carolina:									
Residential	4.48%	2.77%	3.84%	4.06%	3.58%	1.55%	3.34%	4.18%	4.19%
SGS	4.90%	5.39%	5.29%	5.31%	5.06%	3.86%	4.79%	5.46%	5.29%
MGS	4.41%	8.71%	5.55%	5.09%	5.75%	7.19%	5.65%	5.55%	4.88%
SI	4.93%	7.16%	3.86%	2.99%	4.56%	-5.32%	4.01%	-3.65%	3.39%
LGS	5.16%	12.92%	7.10%	5.78%	7.29%	13.19%	8.44%	8.59%	5.30%
Lighting	8.84%	8.85%	8.84%	8.84%	8.89%	8.37%	9.63%	7.71%	8.42%
NC Retail	4.74%	5.03%	4.83%	4.73%	4.80%	4.04%	4.77%	5.22%	4.74%
South Carolina:									
Residential	6.14%	3.61%	5.20%	5.59%	5.08%	2.43%	4.81%	6.01%	5.98%
SGS	6.03%	6.73%	6.04%	6.27%	6.26%	3.93%	5.56%	5.03%	6.51%
MGS	11.38%	17.67%	13.27%	12.48%	13.08%	15.58%	13.18%	12.69%	11.83%
SI	18.25%	15.92%	16.71%	17.85%	17.05%	2.19%	17.48%	7.75%	17.03%
LGS	5.76%	22.46%	8.37%	5.72%	8.11%	13.74%	9.83%	7.50%	4.95%
Lighting	10.31%	10.23%	10.29%	10.31%	10.08%	9.40%	11.34%	8.20%	9.33%
SC Retail	7.40%	8.60%	7.67%	7.30%	7.66%	6.91%	7.84%	7.76%	7.18%

Duke Energy Progress, Inc.

DEP Exhibit 14
Pg 2 of 2

Cost of Service Analysis Results
ROR At Present Rates - After Fuel Adj less Before Fuel Adj
For the twelve months ending December 2018

	After Fuel Adjustment less Before Fuel Adjustment								
	Peak Responsibility Methods				Energy Weighting Methods				Time Differentiated Method
	Summer 1 CP	Winter 1 CP	4CP	12CP	SWPA	A&E	A&E 4CP	A&E Dom	BIP
North Carolina:									
Residential	0.00%	0.00%	0.00%	0.00%	-0.89%	-0.77%	-0.89%	-0.94%	-0.94%
SGS	0.00%	0.00%	0.00%	0.00%	-0.67%	-0.62%	-0.66%	-0.69%	-0.68%
MGS	0.00%	0.00%	0.00%	0.00%	0.53%	0.57%	0.52%	0.52%	0.50%
SI	0.00%	0.00%	0.00%	0.00%	0.26%	0.09%	0.25%	0.12%	0.24%
LGS	0.00%	0.00%	0.00%	0.00%	2.76%	3.59%	2.90%	2.92%	2.43%
Lighting	0.00%	0.00%	0.00%	0.00%	1.24%	1.21%	1.28%	1.17%	1.21%
NC Retail	0.00%	0.00%	0.00%	0.00%	-0.04%	-0.04%	-0.04%	-0.04%	-0.04%
South Carolina:									
Residential	0.00%	0.00%	0.00%	0.00%	-0.90%	-0.76%	-0.89%	-0.96%	-0.95%
SGS	0.00%	0.00%	0.00%	0.00%	-0.88%	-0.76%	-0.84%	-0.82%	-0.88%
MGS	0.00%	0.00%	0.00%	0.00%	0.64%	0.69%	0.64%	0.62%	0.60%
SI	0.00%	0.00%	0.00%	0.00%	0.87%	0.42%	0.88%	0.59%	0.86%
LGS	0.00%	0.00%	0.00%	0.00%	3.61%	4.56%	3.89%	3.46%	2.99%
Lighting	0.00%	0.00%	0.00%	0.00%	1.80%	1.73%	1.91%	1.65%	1.73%
SC Retail	0.00%	0.00%	0.00%	0.00%	0.45%	0.42%	0.45%	0.45%	0.43%

Duke Energy Progress, LLC

DEP Exhibit 15

Single Summer CP Method

Unit Cost Report

Year: 2018

	Demand	UNIT	COSTS	Energy	UNIT	COSTS	CUSTOMER	UNIT	COSTS
	Revenue	KW [1]	$/KW/Mo	Revenue	Annual KWH [2]	Cents/KWH	Revenue	Customers [3]	$/Cust/Mo
North Carolina:									
Residential	875,269,766	3,690,872	19.76	576,845,306	16,666,046,589	3.46	398,044,753	1,199,988	27.64
SGS	107,683,501	458,072	19.59	70,868,603	1,982,596,401	3.57	57,038,037	166,073	28.62
MGS	459,217,424	2,099,254	18.23	406,986,841	11,178,964,878	3.64	16,227,247	38,728	34.92
SI	3,192,168	5,292	50.27	1,635,108	43,075,313	3.80	418,939	851	41.02
LGS	239,150,351	1,204,485	16.55	264,167,036	8,457,791,022	3.12	1,051,493	279	314.07
Lighting	86,223,218	-	N/A	8,422,839	358,793,310	N/A	743,463	858	N/A
TOTAL RETAIL	$ 1,770,736,430	7,457,976	19.79	$ 1,328,925,733	38,687,267,513	3.44	$ 473,523,933	1,406,777	28.05

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Number of Customers

Duke Energy Progress, LLC

DEP Exhibit 16

Single Winter CP Method

Year: 2018

	Demand	UNIT	COSTS	Energy	UNIT	COSTS	CUSTOMER	UNIT	COSTS
	Revenue	KW [1]	$/KW/Mo	Revenue	Annual KWH [2]	Cents/KWH	Revenue	Customers [3]	$/Cust/Mo
North Carolina:									
Residential	953,520,423	5,516,803	14.40	571,085,119	16,666,046,589	3.43	368,187,369	1,199,988	25.57
SGS	103,380,005	513,820	16.77	70,905,407	1,982,596,401	3.58	57,403,580	166,073	28.80
MGS	398,560,764	1,735,671	19.14	415,471,326	11,178,964,878	3.72	18,828,811	38,728	40.52
SI	2,909,962	3,477	69.75	1,652,317	43,075,313	3.84	449,222	851	43.99
LGS	192,419,558	822,814	19.49	275,544,967	8,457,791,022	3.26	1,187,540	279	354.70
Lighting	85,097,655	-	N/A	8,406,302	358,793,310	N/A	734,045	858	N/A
TOTAL RETAIL	$ 1,735,888,367	8,592,584	16.84	$ 1,343,065,439	38,687,267,513	3.47	$ 446,790,566	1,406,777	26.47

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Progress, LLC

DEP Exhibit 17

4 CP - 2 Summer, 2 Winter Method

Year: 2018

	Demand	UNIT	COSTS	Energy	UNIT	COSTS	CUSTOMER	UNIT	COSTS
	Revenue	KW [1]	$/KW/Mo	Revenue	Annual KWH [2]	Cents/KWH	Revenue	Customers [3]	$/Cust/Mo
North Carolina:									
Residential	904,164,120	4,068,413	18.52	574,760,982	16,666,046,589	3.45	387,276,815	1,199,988	26.89
SGS	104,942,612	442,638	19.76	70,935,079	1,982,596,401	3.58	57,637,898	166,073	28.92
MGS	440,247,063	1,919,270	19.12	409,193,213	11,178,964,878	3.66	16,919,899	38,728	36.41
SI	3,316,114	6,807	40.60	1,624,540	43,075,313	3.77	400,441	851	39.21
LGS	224,311,616	1,045,436	17.88	266,983,866	8,457,791,022	3.16	1,073,731	279	320.71
Lighting	85,890,173	-	N/A	8,417,865	358,793,310	N/A	739,070	858	N/A
TOTAL RETAIL	$ 1,762,871,697	7,482,564	19.63	$ 1,331,915,545	38,687,267,513	3.44	$ 464,047,854	1,406,777	27.49

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Progress, LLC

DEP Exhibit 18

12 CP Method

Year: 2018

	Demand	UNIT	COSTS	Energy	UNIT	COSTS	CUSTOMER	UNIT	COSTS
	Revenue	KW [1]	$/KW/Mo	Revenue	Annual KWH [2]	Cents/KWH	Revenue	Customers [3]	$/Cust/Mo
North Carolina:									
Residential	897,134,090	3,546,791	21.08	575,668,610	16,666,046,589	3.45	391,906,233	1,199,988	27.22
SGS	105,248,567	395,739	22.16	70,966,056	1,982,596,401	3.58	57,892,680	166,073	29.05
MGS	448,887,340	1,793,487	20.86	408,445,948	11,178,964,878	3.65	16,657,058	38,728	35.84
SI	3,457,304	7,291	39.51	1,617,715	43,075,313	3.76	388,570	851	38.05
LGS	234,465,486	1,040,008	18.79	265,110,522	8,457,791,022	3.13	1,059,128	279	316.35
Lighting	86,262,000	-	N/A	8,423,207	358,793,310	N/A	740,233	858	N/A
TOTAL RETAIL	$ 1,775,454,786	6,783,316	21.81	$ 1,330,232,057	38,687,267,513	3.44	$ 468,643,903	1,406,777	27.76

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Progress, LLC

DEP Exhibit 19

SWPA Method

Year: 2018

	Demand Revenue	UNIT KW [1]	COSTS $/KW/Mo	Energy Revenue	UNIT Annual KWH [2]	COSTS Cents/KWH	CUSTOMER Revenue	UNIT Customers [3]	COSTS $/Cust/Mo
North Carolina:									
Residential	872,484,135	3,690,872	19.70	576,472,719	16,666,046,589	3.46	396,324,162	1,199,988	27.52
SGS	102,395,700	458,072	18.63	71,035,619	1,982,596,401	3.58	58,469,652	166,073	29.34
MGS	444,235,594	2,099,254	17.63	408,437,669	11,178,964,878	3.65	16,833,962	38,728	36.22
SI	3,248,125	5,292	51.15	1,628,456	43,075,313	3.78	407,206	851	39.88
LGS	242,360,241	1,204,485	16.77	263,126,857	8,457,791,022	3.11	1,040,709	279	310.84
Lighting	87,936,312	-	N/A	8,326,583	358,793,310	N/A	728,636	858	N/A
TOTAL RETAIL	$ 1,752,660,106	7,457,976	19.58	$ 1,329,027,903	38,687,267,513	3.44	$ 473,804,328	1,406,777	28.07

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Progress, LLC **DEP Exhibit 20**

Average & Excess Method

Unit Cost Report

Year: 2018

	Demand	UNIT	COSTS	Energy	UNIT	COSTS	CUSTOMER	UNIT	COSTS
	Revenue	KW [1]	$/KW/Mo	Revenue	Annual KWH [2]	Cents/KWH	Revenue	Customers [3]	$/Cust/Mo
North Carolina:									
Residential	1,024,694,579	4,754,335	17.96	572,893,970	16,666,046,589	3.44	376,639,206	1,199,988	26.16
SGS	113,585,322	456,013	20.76	70,946,657	1,982,596,401	3.58	57,724,378	166,073	28.97
MGS	440,409,065	1,567,875	23.41	413,458,342	11,178,964,878	3.70	18,095,087	38,728	38.94
SI	6,502,745	42,990	12.61	1,552,048	43,075,313	3.60	274,391	851	26.87
LGS	216,184,142	744,638	24.19	271,825,214	8,457,791,022	3.21	1,155,060	279	345.00
Lighting	92,086,845	-	N/A	8,343,489	358,793,310	N/A	765,389	858	N/A
TOTAL RETAIL	$ 1,893,462,698	7,565,851	20.86	$ 1,339,019,721	38,687,267,513	3.46	$ 454,653,511	1,406,777	26.93

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Progress, LLC

DEP Exhibit 21

Average & Excess 4CP Method

Unit Cost Report

Year: 2018

	Demand	UNIT	COSTS	Energy	UNIT	COSTS	CUSTOMER	UNIT	COSTS
	Revenue	KW [1]	$/KW/Mo	Revenue	Annual KWH [2]	Cents/KWH	Revenue	Customers [3]	$/Cust/Mo
North Carolina:									
Residential	884,760,019	2,096,469	35.17	575,885,968	16,666,046,589	3.46	393,185,537	1,199,988	27.30
SGS	104,156,336	231,995	37.41	70,976,221	1,982,596,401	3.58	57,978,782	166,073	29.09
MGS	446,848,626	1,064,200	34.99	408,323,831	11,178,964,878	3.65	16,712,635	38,728	35.96
SI	3,326,941	3,843	72.14	1,623,847	43,075,313	3.77	399,193	851	39.09
LGS	235,384,079	627,005	31.28	264,674,754	8,457,791,022	3.13	1,053,995	279	314.81
Lighting	86,807,112	-	N/A	8,380,336	358,793,310	N/A	735,080	858	N/A
TOTAL RETAIL	$ 1,761,283,113	4,023,512	36.48	$ 1,329,864,956	38,687,267,513	3.44	$ 470,065,222	1,406,777	27.85

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Progress, LLC

DEP Exhibit 22

Average & Excess - Dominion Method

Unit Cost Report

Year: 2018

	Demand	UNIT	COSTS	Energy	UNIT	COSTS	CUSTOMER	UNIT	COSTS
	Revenue	KW [1]	$/KW/Mo	Revenue	Annual KWH [2]	Cents/KWH	Revenue	Customers [3]	$/Cust/Mo
North Carolina:									
Residential	824,803,227	3,515,681	19.55	576,942,951	16,666,046,589	3.46	399,105,416	1,199,988	27.72
SGS	98,257,364	402,325	20.35	71,011,916	1,982,596,401	3.58	58,412,828	166,073	29.31
MGS	438,945,973	2,057,753	17.78	407,087,924	11,178,964,878	3.64	16,104,711	38,728	34.65
SI	4,982,535	32,970	12.59	1,545,900	43,075,313	3.59	273,649	851	26.80
LGS	229,796,645	1,186,807	16.14	264,040,975	8,457,791,022	3.12	1,015,972	279	303.46
Lighting	88,287,976	-	N/A	8,226,969	358,793,310	N/A	710,109	858	N/A
TOTAL RETAIL	$ 1,685,073,722	7,195,535	19.52	$ 1,328,856,635	38,687,267,513	3.43	$ 475,622,685	1,406,777	28.17

[1] Allocation Factor: All - Production Demand at Meter

[2] Allocation Factor: All - Kwhr at Meter

[3] Allocation Factor: All - Cust Num

Duke Energy Carolinas and Duke Energy Progress **DE Exhibit 1**

Comprehensive Cost of Service Study

<u>Strengths and Weaknesses Matrix</u>

Line No.	Description	SCP	WCP	4CP	12CP	SWPA	A&E	A&E (4CP)	A&E (Dom)	BIP
	STRENGTHS									
1	Multiple CP methods are commonly used and accepted by FERC				X					
2	Encourages shifting of usage to off-peak times	X	X							
3	Easy for customer to understand	X	X							
4	Data requirements are not burdensome	X	X	X	X	X				
5	Calculations are relatively simple	X	X	X	X	X				
6	Captures seasonal variation in a utility's loads			X	X					
7	Creates a more normalizing or smoothing effect from year to year			X	X					
8	Reflects the concept that the utility called on almost all of its generating resources during the highest peak months but only its more efficient generating units during the lower peak periods (The resulting allocated costs recognize/consider the capacity/energy tradeoff for the twelve monthly peaks under evaluation)				X					
9	Since each monthly peak is weighted equally in calculating the annual average peak, peaks caused by extreme weather in any month are moderated.				X					
10	Recognizes that generation is built to meet both peak demands and energy usage (to meet load both 'instantaneously' and 'over time')					X	X	X	X	X
11	Takes into consideration the generation facilitates needed to serve the company's "average load," as well as its "peak load", in assigning cost responsibility					X	X	X	X	
12	Since excess demand is peak demand less average demand, it avoids the double counting issue prevalent in the peak and average methods						X	X	X	
13	Provides incentive for customers with low load factors to lower demand which aligns with the company's pricing that encourages off-peak usage							X		
14	Does not penalize classes of customers for incurring peak demands during off peak months							X		
15	Recognizes capacity/energy tradeoff					X	X	X	X	X
16	Specifically recognizes the mix of a utility's resources used to serve the varying demands throughout the year									X
17	Permits the weighting of expensive base load plants versus less expensive peak load units									X
18	Method can be modified to accommodate the diversity of generation resources									X

Duke Energy Carolinas and Duke Energy Progress **DE Exhibit 2**

Comprehensive Cost of Service Study

Strengths and Weaknesses Matrix

Line No.	Description	SCP	WCP	4CP	12CP	SWPA	A&E	A&E (4CP)	A&E (Dom)	BIP
	WEAKNESSES									
19	Ignores capacity/energy trade-off	X	X	X	X					
20	Assigns same weight to expensive base load unit that provides energy throughout the year as it does a relatively inexpensive peaking unit that provides energy for only a few hours a year	X	X	X	X					
21	Ignores use of generation system other than the peak hour of the year	X	X	X	X					
22	Results can be unstable from year-to year due to the peak being driven by severe weather events	X	X	X	X					
23	Suffers from the "free-ride" phenomenon where, for ex., lighting class maybe not be assigned any cost	X	X	X	X					
24	Utilities do not design their generating systems to meet twelve peaks				X					
25	Significant amount of fixed capacity cost is allocated based on energy consumption which harms high-load factor customers					X	X	X	X	X
26	No consideration is given to the lower fuel costs incurred during off-peak hours					X	X	X	X	X
27	Calculation double counts average load (this occurs because the peak demand segment contains an average load component)					X				
28	Moves peak demand cost responsibility towards lower load factor customer classes						X	X	X	
29	Can produce results that are an outlier as compared to other methods									X
30	Fails to consider that baseload units are not simply operated for purposes of providing energy, but also contribute towards meeting peak demand									X
31	Penalizes high load factor customers that use the system in a more efficient manner					X				X
32	Inherently assumes that the test year use of each generator (B, I, or P) reflects the way in which plant will be used over its remaining operating life									X
33	Method has not been adopted by any state commission									X
34	Method requires a set of decisions about the definition of the generation classes and the classification percentage for each class									X

Duke Energy Carolinas, LLC - Docket No. E-7, Sub 1214
Duke Energy Progress, LLC - Docket No. E-2, Sub 1219

DE Exhibit 3

Cost of Service Study - Participants

	Participant	Organization
1	Laura Bateman	Duke Energy
2	Ginny Boucher	Duke Energy
3	Kim H Smith	Duke Energy
4	Kaari Beard	Duke Energy Carolinas
5	Karen Keller	Duke Energy Carolinas
6	Sumita Deshmukh	Duke Energy Progress
7	LaWanda Jiggetts	Duke Energy Progress
8	Skip Seekamp	Duke Energy
9	Paul Halstead	Duke Energy
10	Brad Harris	Duke Energy
11	Jack Floyd	Public Staff - North Carolina Utilities Commission
12	James McLawhorn	Public Staff - North Carolina Utilities Commission
13	Lucy Edmondson	Public Staff - North Carolina Utilities Commission
14	Bob Hinton	Public Staff - North Carolina Utilities Commission
15	Benjamin Lozier	Public Staff - North Carolina Utilities Commission
16	Mike Maness	Public Staff - North Carolina Utilities Commission
17	Jeff Thomas	Public Staff - North Carolina Utilities Commission
18	Tommy C. Williamson	Public Staff - North Carolina Utilities Commission
19	David Williamson	Public Staff - North Carolina Utilities Commission
20	Michelle Boswell	Public Staff - North Carolina Utilities Commission
21	Christina D. Cress	CIGFUR
22	Nick Phillips	Brubaker & Associates, Inc.
23	Steve Castracane	Messer
24	David L. Neal	SELC
25	Dennis Derricks	Facebook
26	Peter H. Ledford	NC Sustainable Energy Association
27	Ben Smith	NC Sustainable Energy Association
28	Michael Seaman-Huynh	South Carolina Office of Regulatory Staff
29	Anthony Sandonato	South Carolina Office of Regulatory Staff
30	Tyler Fitch	Vote Solar
31	Hasala Dharmawardena	
32	Kevin O'Donnell	CUCA
33	Margaret A. Force	NC DOJ - Attorney General
34	Teresa L. Townsend	NC DOJ - Attorney General

CIGFUR's primary concerns with the Base, Intermediate and Peaking ("BIP") method as proposed and discussed during the Cost of Service Study Group meeting on July 13, 2021:

- The BIP methodology is not an accepted method of allocating production plant and should not be endorsed by this Study Group. Moreover, the inherent flexibility built into this method can lead to a number of arguably arbitrary decisions surrounding implementation of this methodology, which will be ripe fodder for opponents in a rate case and/or a legal challenge on appeal.
    - "While the base-peak classification approach and related methods are highly flexible, that is both their greatest strength and a great weakness. The strength is that the method can be modified to accommodate the diversity of generation resources; the weakness is that the method requires a set of decisions about the definition of the generation classes and the classification percentage for each class. The base-peak method is connected to actual utility planning only at the highest conceptual level and provides limited guidance for the nitty-gritty details of traditional classification." RAP, Electric Cost Allocation for a New Era, p. 113.

- The BIP methodology as interpreted would be inconsistent with system planning in that it minimizes the need for, and value of, capacity by over-allocating on an energy basis. Over-classifying costs as energy-related in turn leads to an over-recovery via energy charges, which in turn results in a disproportionate assignment of costs to the industrial class, and specifically to high load factor customers within that class.

- The methodology as interpreted, and as applied, would deviate from cost causation principles (and Jack Floyd conceded as much during the call on July 13, 2021 when he stated that higher load customers do not support having to pay a large share for peak resources that are not driven by those same customers' use of such resources).

- Normally, a utility doesn't plan to construct intermediate generation, most often it is plant that has aged and no longer efficient. Allocating such plant as if it were planned is problematic at best.

- A significant issue with this method and other methods that allocate relatively more base load plant to high load factor classes is the fuel symmetry problem. The allocation of fuel costs would require a great deal of additional study so that lower fuel cost is allocated to the classes that received the higher allocation of base load plant. This would require a great deal of modeling and study and based on prior experience would burden this process with an allocation method that is unproven and not seriously considered for adoption by this commission or most others, if any.

- See also Rebuttal Testimony of William R. Hopkins, Duke Energy Carolinas, LLC, Docket No. E-7, Sub 909, pp. 14-16; https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=9d581cc4-3018-4ef4-973f-69822db9e57f.