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January 23, 2018

FILED
JAN 23 2018
Clerk's Office
N.C. Utilities Commission

Ms. M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
Dobbs Building, Fifth Floor
430 North Salisbury Street
Raleigh, North Carolina 27602

Re: Duke Energy Carolinas' Application for Adjustment of Rates and Charges Applicable To Electric Service in North Carolina
Docket No. E-7, Sub 1146

VIA HAND DELIVERY

Dear Ms. Jarvis:

In connection with the above-captioned docket, I transmit herewith for filing on behalf of Carolina Utility Customers Association, Inc. ("CUCA") the original single-sided, plus 34 double-sided copies of the Testimony and Exhibits of Kevin W. O'Donnell, CFA, Nova Energy Consultants.

Kindly date-stamp and return to us via our courier the four (4) additional enclosed copies. Please let me know, at your early convenience, if you have any questions concerning this filing.

Very truly yours,

CRISP & PAGE, PLLC

Robert F. Page

Robert F. Page

Enclosures

cc: Sharon Miller
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(1924-1992)

CERTIFICATE OF SERVICE

I, the undersigned counsel for CUCA, do hereby certify that I served a copy of the foregoing Direct Testimony of Kevin W. O'Donnell, CFA, upon all parties of record in this proceeding, or their legal counsel, by electronic mail or by depositing a copy of same in the United States Postal Service, first class, postage prepaid, and addressed to them as indicated on the Service List attached hereto.

This the 23rd day of January, 2018.

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BEFORE THE NORTH CAROLINA UTILITIES COMMMISSION

DOCKET NO. E-7 SUB 1146

DIRECT TESTIMONY

AND EXHIBITS

OF

KEVIN W. O'DONNELL, CFA

ON BEHALF OF THE

CAROLINA UTILITY CUSTOMERS ASSOCIATION, INC.

January 23, 2018

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc. My business address is 1350 Maynard Rd., Suite 101, Cary, North Carolina 27511.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of the Carolina Utility Customers Association (CUCA). A number of CUCA members take retail electric service from the applicant, Duke Energy Carolinas (DEC or Company), and the outcome of this proceeding will have a direct bearing on these CUCA members.

Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science in Civil Engineering from North Carolina State University and a Master of Business Administration from the Florida State University. I earned the designation of Chartered Financial Analyst ("CFA") in 1988.

I have worked in utility regulation since September 1984, when I joined the Public Staff of the North Carolina Utilities Commission ("NCUC"). I left the NCUC Public Staff in 1991 and have worked continuously since then in utility consulting: first with Booth & Associates, Inc. as a financial analyst and then as

Director of Retail Rates for the North Carolina Electric Membership Corporation from 1994 to 1995, and since then as principal for my own consulting firm.

I have been admitted as an expert witness on rate of return, cost of capital, capital structure, cost of service, rate design, and other regulatory issues in general rate cases, fuel cost proceedings, and other proceedings before the following regulatory bodies: the North Carolina Utilities Commission; the South Carolina Public Service Commission; the Wisconsin Public Service Commission; the Maryland Public Service Commission; the Virginia State Commerce Commission; the Minnesota Public Service Commission; the New Jersey Board of Public Utilities; the Colorado Public Utilities Commission; the District of Columbia Public Service Commission; and the Florida Public Service Commission.

In 1996, I testified before the U.S. House of Representatives' Committee on Commerce and Subcommittee on Energy and Power, concerning competition within the electric utility industry. Additional details regarding my education and work experience are set forth in Appendix A of this testimony.

II. PURPOSE OF TESTIMONY

Q. PLEASE DESCRIBE THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present my findings and recommendations to the Commission as to the proper rate of return to allow Duke Energy Carolinas ("DEC" or "Company") in the current proceeding. I have been asked to provide an opinion regarding the Company's proposed capital structure and rate of return in its request before the North Carolina Utilities Commission ("NCUC" or "Commission") for the authority to increase rates and charges for electric service. To be specific, I have been asked to respond to the following issues:

- the trend in DEC industrial rates and associated impact on the North Carolina economy;
- DEC's proposed grid rider known as GRRR;
- the appropriate amount of coal ash expense to be included in DEC's rates;
- the appropriate amount of rate case expenses;
- the rate of return to be used in setting rates;
- the pre-filed testimony of Company Witness Hevert; and
- cost of service and rate design

III. SUMMARY/RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR PRIMARY RECOMMENDATIONS IN THIS CASE.

A. My recommendations are as follows:

- DEC's manufacturing rates are trending upward and, with this rate increase, will be above the national average thereby causing more economic distress to areas served by the Company;
- DEC's proposed grid resiliency and reliability rider (GRRR) is too expensive, will harm the State's economy, and should be disallowed;
- In an effort to restrain the growth in residential and commercial rates and provide much needed relief for struggling manufacturers, the Commission should allow the Duke-proposed Job Retention Tariff (JRT);
- the Commission should disallow at least 75% of DEC's coal ash request in this case;
- DEC's rate case expenses in this case are an example of Duke being tone deaf to the economic hardship of North Carolinians;
- the return on equity recommended by Company Witness Hevert is excessive, unreasonable, and lacks basic evidentiary support;
- the proper return on equity on which to set rates for DEC in this proceeding should be set at 9.0%;
- the proper capital structure to employ in this proceeding is 50% common equity and 50% long-term debt;
- I am not proposing a change to DEC's use of its embedded cost of long term debt of 4.74% for its debt costs;
- the overall rate of return that should be set for ratemaking purposes is 6.87%; and
- DEC's use of the summer coincident peak (CP) cost of service is appropriate.

IV. DISCUSSION

1. Energy Costs for Manufacturers Located in DEC Service Territory

Q. PLEASE EXPLAIN THE IMPORTANCE OF ENERGY COSTS TO LARGE MANUFACTURING OPERATIONS.

A. Manufacturers are in a constant battle to survive. The competition is international, domestic, and amongst sister plants of the same company. If the cost to manufacture a particular product is less expensive in another state or country, the manufacturer has a duty to its customers and stockholders to move the manufacturing to the area of least cost. In my 33 years of experience in the utility industry, I have spoken to many manufacturing representatives in North Carolina, South Carolina, and other states that have provided me examples of manufacturers moving operations due to costs. Sometimes the movements result in permanent plant shutdowns and mass layoffs. Other times, the movements result in line reductions such that the current plant temporarily ceases operation.

An example of a temporary shutdown is a NC plant that produces an identical product as, for example, a sister plant in Georgia. Manufacturers planning their daily production schedules can look at NC prices on a day ahead hourly basis and compare those prices to the Georgia hourly prices. In many circumstances, the NC hourly electric prices are higher than the Georgia prices and the NC plant does not operate a certain line the next day. In such a case, the NC utility loses a potential sale, but the loss is not reported in the press such as the reporting of a permanent plant closing. However, over time, the daily losses of load add up and jobs are eventually lost.

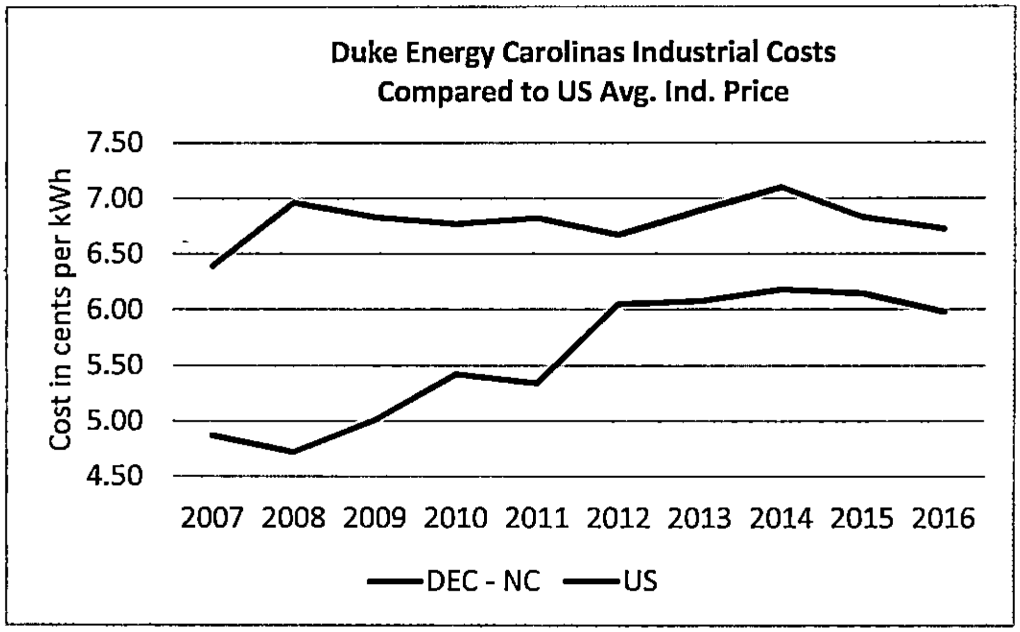
Q. ARE YOU SAYING THAT ELECTRIC COSTS ARE THE ONLY REASON MANUFACTURERS CHOOSE TO LOCATE/OPERATE IN A PARTICULAR STATE?

A. No. Manufacturers locate and operate in certain areas for a myriad of different reasons. The cost of electricity is one concern for manufacturers, but that concern is magnified the greater the state being examined is out-of-line relative to competing states. Energy intensive industries such as steel, air products, auto manufacturers, and paper companies are particularly sensitive to cost imbalances in the electric industry.

Q. HOW HAVE THE DEC RATES COMPARED TO THE NATIONAL AVERAGE OVER THE PAST 10 YEARS?

A. Chart no. 1 below shows this cost comparison from 2007 through 2016. Overall, it appears the DEC industrial rates have, historically, been slightly below the national average. However, if this rate case increase is granted in its entirety, DEC's industrial rates will be approximately equal to the national average. Furthermore, the forecast for future rate increases for DEC is not good for consumers as Duke's leaders have made it known that the current rate case is but the first of many rate cases to come in between now and 2021. If DEC's plans come to fruition, DEC's industrial rates will soon be well above the national average thereby doing great economic harm to the State and its citizens.

Chart 1: Historical DEC Costs Compared to National Average



Source for raw data: US Energy Information Administration

2. Duke's Planned Grid "Updates"

Q. WHY IS DUKE PLANNING TO FILE FREQUENT RATE CASES IN THE FUTURE?

A. Duke has made a very public announcement that it intends to "invest" $13 billion to "modernize" the electric infrastructure in North Carolina. This "modernization" comes with a very expensive price tag for consumers. On Feb. 10, 2017 Ms. Kendal Bowman of Duke Energy made a presentation to the NC Legislative Working Group and provided the **annual** rate increases expected by Duke over the next 10 years to pay for its proposed "investment" in the State. Table 1 below provides these annual rate hikes as stated by Ms. Bowman on Feb. 10, 2017:

Table 1: Duke Energy Rate Increases for Grid Modernization

$10 Billion Spend	
Customer	Utility

Class	DEC	DEP
Residential	4.31%	4.05%
Commercial	1.18%	3.45%
Industrial	2.65%	0.86%

Source: Ms. Kendal Bowman at NC Leg. Working Group on Feb. 10, 2017

Q. OTHER THAN THE FEB. 10, 2017 PRESENTATION OF MS. BOWMAN BEFORE THE NORTH CAROLINA LEGISLATIVE WORKING GROUP, HAS DUKE MADE ANY OTHER PUBLIC PRESENTATION AS TO THE COSTS OF ITS PROPOSED GRID INVESTMENT PLAN?

A. Not to our knowledge. Duke has been very upfront with the benefits it perceives with its grid modernization plans, but it has not been forthcoming at all to the general public concerning the costs associated with the plan. I take particular exception to the following statement found in Mr. Fountain's direct testimony in this case.

> **Q. IS THE COMPANY PROACTIVELY EDUCATING CUSTOMERS ABOUT THIS PROPOSED BASE RATE ADJUSTMENT?**
>
> A. Yes. DE Carolinas is committed to being transparent and keeping customers informed about the costs included in their bills and proposals to adjust rates. The Company has provided information to the public through news releases and media interviews, op-eds from company executives, social media content, advertising, speeches and print materials. We have also been very transparent about our investments to build a smarter energy future for our customers powered by cleaner, more efficient energy sources such as highly efficient natural gas, carbon-free nuclear energy, and renewable resources like hydroelectric generation and solar energy. [1]

1 Pre-filed testimony of David Fountain, p. 26, l. 11-20

Unfortunately, Duke has **NOT** been transparent with the public in respect to the **costs of its grid modernization efforts**. Below is a data request item and Duke's response to the question:

CUCA 1-7 Request:

> In Duke's efforts to educate citizens of the State regarding grid modernization efforts, has Duke disclosed the annual cost to consumers for the Company's efforts? If not, why not?
>
> **Response:**
>
> The Company announced the grid modernization plan (Power Forward Carolinas) and highlighted the estimated costs over the full 10-year period. Additionally, the Company defined the estimated costs for the seven major components. The annual costs for the full 10 years was not shared as they rely on a multitude of factors, some of which are yet to be determined. In the current rate case, the Company has requested approval for the grid reliability and resiliency rider (GRRR) and proposed initial rates, as shown on Pirro Exhibit 9. (underline added) [2]

Duke's response to CUCA data request no. 1-7 conflicts with the information shared by Ms. Bowman with the NC General Assembly in Feb, 2017. In that presentation, Ms. Bowman provided very specific cost increases to the Legislative Working Group. However, in the above response, Duke states that rate impact has not yet been shared because of a "multitude of factors, some of which are yet to be determined."

In our view, Duke has NOT been upfront with consumers as to its plans to hike rates substantially to pay for grid investments in the State. Instead, Duke promotes a very idealistic view of its "investments" but fails to inform the consuming public of the associated costs. Duke's story to the media is akin to a baker telling you to go ahead and eat the entire chocolate cake because it will be

[2] Duke response to CUCA DR 1-7

good for you, but Duke doesn't tell how many calories are in the cake. Duke is not being forthright with the entire story of its proposed GRRR.

Q. CAN YOU PUT THE RATE INCREASES FROM TABLE 2 INTO MORE PERSPECTIVE IN TERMS OF THE ACTUAL COSTS TO NORTH CAROLINA CONSUMERS?

A. Yes, these rate impacts are best put into context by translating these annual rate hikes into a cumulative rate increase over 10 years. Table 2 below provides the cumulative rate hike % requested by Duke for the grid updates.

Table 2: Cumulative Rate Increase for Duke's Proposed Grid Investments

$10 Billion Spend		
Customer Class	Utility	
	DEC	DEP
Residential	52.50%	48.74%
Commercial	12.45%	40.38%
Industrial	29.89%	8.94%

P. 12 of Duke presentation of 2-10-17 calls for 10-year grid program

The above % rate change increases can be further granulated into annual cost increases for Duke customers over the life of Duke's proposed 10-year roll-out of its grid update plans. Table 3 below provides the cumulative cost increases associated strictly with Duke's grid updates.

Table 3: Per Customer Cost for Duke Grid Updates

$10 Billion Spend	
Customer	Utility

Class	DEC	DEP
Residential	$3,792	$3,664
Commercial	$161,712	$562,286
Industrial	$14,459,325	$4,819,534

For residential consumers, the above table assumes a consumption of 1,100 kWhs per month using the average DEC residential cost in North Carolina as reported by the EIA. For commercial consumers, the table was constructed using a 500 kW load with a 70% load factor and a corresponding EIA average cost. Lastly, the industrial values were calculated using a 20 MW load, an 85% load factor, and cost data as reported by EIA.

It is important to note that these cost increases do not go away after 10 years. Duke will depreciate the plant and equipment over time and, by doing so, will keep rates elevated for the life of the assets.

Duke is calling its planned grid investments "Power/Forward Carolinas." Based on the rate hikes as stated in Table 3 above, a more appropriate name for these grid investment modernizations is "GRIM," since implementation of Duke's plan will have grim financial consequences for NC consumers and the economy of the State.

If, as Mr. Fountain claims, "DE Carolinas is committed to being transparent and keeping customers informed about the costs included in their bills and proposals to adjust rates," Duke would include rate increase estimates as provided by Ms. Bowman (and as noted above) when running media advertisements touting the virtues of Power Forward. Clearly, Duke is not being transparent about the GRRR costs to consumers. Instead, we believe that the Company is hoping consumers do not understand the magnitude of Duke's grid expense requests and, consequently, do not mobilize opposition against Duke's plans, either at the Commission or in the General Assembly.

Q. HAS DUKE UPDATED ITS PROJECT GRIM EXPECTED COSTS?

A. Duke did provide CUCA a data request response that showed slightly different cost projections for Project GRIM, but the costs were truncated at year 2026 and, as such, did not provide the costs forecasts through the expected 10-year roll-out period for Project GRIM. In Feb. 2017, Ms. Bowman provided annual cost increases for the 10-year project. Duke DR response to CUCA in this matter provided only cost increases for 8-years. However, Duke has publicly stated that its grid update plan will take place over 10 years.[3] Either Duke has chosen to cut back on its grid update plan OR its response to CUCA data request was incomplete as the data request response did not provide the projected rate increases for 2027 and 2028.

Of particular interest is that Duke stamped the DR response as confidential thereby, once again, showing the Company is unwilling to be transparent with legislators, this Commission, or ratepayers in North Carolina.

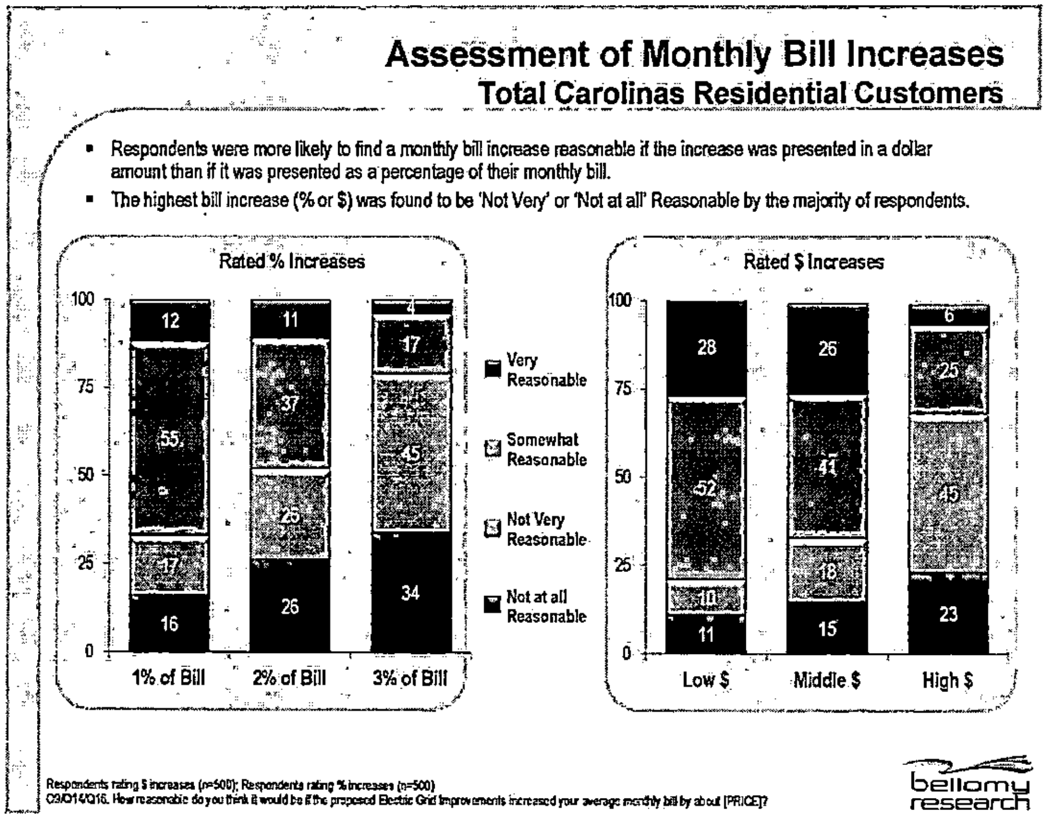
Q. HAS DUKE COMPLETED ANY MARKETING SURVEYS TO ASSESS CUSTOMER INTEREST IN PROJECT GRIM?

A. Yes. On July 6, 2015, Bellomy Research presented the findings of its marketing survey regarding Duke's "Electric Grid Improvements."[4] While most individuals indicated they were in favor of an improved grid, the data below shows consumers have their limit. Specifically, the data below shows that 79% polled found Duke's grid improvements were "not very reasonable" or "not at all reasonable" when the cost increase was 3% per month.

3 https://news.duke-energy.com/releases/duke-energy-embarks-on-a-10-year-initiative-to-strengthen-north-carolina-s-energy-grid

4 Duke response to CUCA DR 2-21

Chart 2: Duke Customer Survey



Keep in mind from Table 3 above shows, based on data provided by Duke, that Duke itself is projecting rate increases that will total 52.5% over the next 10 years to pay for Project Grim. If 79% of respondents feel that 3% is too much to pay for the grid updates, I am certain that well over 95% would be opposed to a 52.5% rate hike from Duke.

The above marketing survey results are the most likely reason why Duke has not publicly announced a cost for Project Grim. Consumers would simply be apoplectic to discover a 52.5% rate hike in their bills to pay for the massive grid updates as proposed by Duke.

These results also discredit Mr. Fountain's claim that Duke has been transparent with its customers regarding the cost for Project Grim. With 79% of survey respondents opposing a 3% rate hike, and Duke is proposing a 52.5% GRR rate hike, there is little wonder why Duke has been silent on the massive costs associated with Project Grim.

Q. HAS THE ISSUE OF A RATE RIDER FOR DUKE'S GRID EXPENSES BEEN PREVIOUSLY RAISED AT THE NORTH CAROLINA GENERAL ASSEMBLY?

A. Yes. In the most recent session of the General Assembly, Duke's team of lobbyists did attempt to have legislation passed that would impose a rate rider for Duke's proposed grid expenses. Such legislation was not enacted.

Q. PLEASE DESCRIBE DUKE'S PRESENCE IN THE NORTH CAROLINA GENERAL ASSEMBLY.

A. Duke's political power in the General Assembly is virtually unmatched.

Duke's lobbyists maintain a near-constant presence in the North Carolina General Assembly. Since Duke failed to get the NC General Assembly to pass its Project Grim legislation during the 2017 session, it has now come before the NC Utilities Commission to ask for a cost recovery rider the Legislature specifically chose not to act upon. Clearly, Duke's request in this case puts a tremendous amount of pressure on the Commission to act on a matter upon which the General Assembly elected not to act.

Q. ARE YOU SAYING THAT DUKE SHOULD NOT INVEST ANY MONIES AT ALL INTO MAINTAINING ITS ELECTRIC GRID?

A. No. I realize that Duke must continue to update its grid and provide reliable service to its consumers. I also realize there are certain grid investments that may benefit renewable energy advocates and provide overall benefits to the state. However, DEC is already engaged in significant plant investments in transmission and distribution. In his prefiled testimony, Company Witness Simpson states that DEC has invested $2.55 billion in transmission and distribution infrastructure since its last rate case.[5] This staggering amount of T&D investment begs the following questions:

1. Why does DEC need a grid cost recovery rider when it is already investing billions of dollars in T&D equipment today?; and

2. What has DEC specifically done with the $2.55 billion expended in T&D capital investment since its last rate case and why does it need even **MORE RATEPAYER DOLLARS** for T&D capex?

Q. WHY DO YOU BELIEVE DEC IS REQUESTING THE GRRR IN THIS CASE AFTER IT JUST INVESTED $2.55 BILLION IN T&D CAPEX SINCE ITS LAST RATE CASE IN 2013?

A. Duke management has clearly and unequivocally stated that it intends to drive earnings in the future through grid investments. However, instead of taking the traditional route of spending its own money and then filing for cost recovery in a rate case, Duke is now seeking to defer risk onto consumers by asking for an automatic forward-looking cost recovery mechanism such as the GRR rider. This effort to shift risk to consumers will allow Duke to make annual investments and obtain immediate rate treatment without the full review of all its other operating expenses. In essence, Duke is asking to be "deregulated" in terms of rate recovery while still holding complete franchise rights in a totally monopolistic service territory.

Q. DO YOU HAVE ANY EVIDENCE TO SUPPORT YOUR BELIEF THAT DUKE'S OBJECTIVE WITH ITS "PROJECT GRIM" IS TO DRIVE EARNINGS?

5 Prefiled testimony of Robert Simpson, III, 9

A. Yes. First, it goes without saying that the business model for any electric utility is that it has two ways of making money in the future. First, the utility can remain as a pure monopoly and drive earnings through capital investment to be paid by captive ratepayers. Secondly, the utility can venture into unregulated activities and take the same risks as do all other companies. Duke has recently made a concerted effort to remove itself from virtually all aspects of unregulated activities as evidenced by the recent sale of its international businesses in 2016 and its unregulated Midwest generation business in 2014. Duke further entrenched its operations as a pure territorial monopoly business when it purchased Piedmont Natural Gas with its existing territorial monopoly operations in the Carolinas.

By moving more towards becoming a pure territorial monopoly business, Duke executives realize their best way to grow their earnings is to ask for continuous rate hikes from North Carolina consumers to pay for plant investments. Evidence for this statement can be seen in the June 15, 2017 edition of the S&P Global Market Intelligence Financial Focus report on Duke Energy which states (in part):

> With unmatched scale and the largest capital expenditure program in the industry, Duke Energy might be considered the leading infrastructure investment in the country at an opportune time, politically speaking. Following the exit from its Brazilian and remaining Latin American operations last year, and its acquisition of Piedmont Natural Gas, Duke has transitioned to a pure domestic infrastructure business. To recapture its earnings growth of years past and allow higher capital deployment, however, timely rate case execution is paramount. [6]

This same report goes on to state the following:

> Additionally, Duke is working to advance legislation in the Carolinas — its primary service territory — that would improve

6 S&P Global Market Intelligence Financial Focus, June 15, 2017

> regulatory cost recovery mechanisms and reduce regulatory lag, and could be an important earnings growth driver in years ahead.[7]

This last statement reflects Duke's failed attempt to obtain GRR legislation in the 2017 long session in North Carolina that would have required North Carolina consumers to pay upfront for Duke's grid expansion.

The same S&P report cited above goes on to state:

> Over the next five years, Duke plans to spend $37 billion across its business platform **to drive robust consolidated adjusted earnings growth of 4%-6% annually**. (underline and bold added) [8]

Duke CEO Lynn Good further admitted the goal to drive earnings by stating the following to the Barclays CEO Energy-Power Conference in New York

> It is also important that we pursue regulatory and legislative initiatives that underpin our ability to deliver returns and turn those investments into cash and returns to shareholders[9] (underline added)

This statement is further supported by the June 27, 2017 edition of The Motley Fool which states:

> One of the ways that utilities grow their businesses is by convincing regulators that they need to raise rates to cover capital spending.......
>
> For reference, Duke's earnings growth target over the next few years for its utility business is for between 4% and 5%. The type of infrastructure spending and rate case activity it's undertaking in North Carolina is going to be the foundation on which Duke grows its business for years to come. [10]

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7 id

8 id

9 *Charlotte Business Journal*, Sept. 7, 2017, 1

10 *The Motley Fool*, June 27, 2017

Q. IS THE DECISION BY DUKE MANAGEMENT TO FOCUS ON GRID EXPANSION UNIQUE TO DUKE OR IS IT AN INDUSTRY TREND?

A. Grid "modernization" efforts are an industry trend. Electric utility load growth is much flatter than in recent years and this lack of sales has caused utilities across the country to search for new ways to drive earnings. On Nov. 8, 2017, Bloomberg published an article entitled "No Sales Growth? No Problem! Utilities See Money in Grid Repairs." The article succinctly captures the grid "modernization" efforts in the following statement:

> Utilities make money by investing in wires, poles, substations and power plants and getting a guaranteed return by their regulators on those investments. But as demand for electricity has flat-lined for nearly a decade, companies are finding it harder to justify just building more stuff for growth. So now, they're talking about making the grids they do operate more efficient and flexible, which also happens to cost money. [11]

So, in essence, Duke management has realized that, to continue to grow earnings, it has to stop focusing on building new generation plant and, instead, build something else. In this case, the "something else" is grid "modernization" plant. The core questions for this Commission is whether Duke's massive grid efforts are needed and if so are they cost beneficial and prudent expenditures for North Carolina consumers.

From a financial standpoint, Duke's plan involves a VERY large expenditure that has the potential to do financial harm to the State's economy. Manufacturers, in particular, stand to be hurt by these Duke grid updates as many simply will not be able to afford the massive cost increases forecasted by Duke.

[11] Bloomberg, Nov. 8, 2017, "No Sales Growth? No Problem! Utilities See Money in Grid Repairs"

Q. IS DUKE GUARANTEED TO EARN A PROFIT AND GROW ITS EARNINGS THROUGH ELECTRIC SERVICE IN NORTH CAROLINA?

A. No. Nothing in the statutes guarantees Duke the right to constantly raise rates to grow the Company's earnings. In fact, Duke management should take note of the following statement from the last major order for an electric case in North Carolina. In Docket No. E-22, Sub 532, the Commission made the following statements:

> ...as North Carolina law requires, setting the ROE at this level merely affords DNCP the opportunity to achieve such a return. See G.S. 62-133(b)(4). The Commission believes, based upon all the evidence presented, that the ROE provided for here will indeed afford the Company <u>the opportunity</u> to earn a reasonable and sufficient return for its shareholders while at the same time producing rates that are fair to its customers. [12] (underline added)

A territorial right to provide electric service in North Carolina does not guarantee Duke an unending string of rate increases to enhance earnings. Duke could cut its expenses, just as business and individuals may be compelled to do if Duke's proposed rate increase is approved by the Commission. Duke could also invest in unregulated businesses to drive earnings.

Q. DO YOU BELIEVE DUKE'S PROPOSED GRID INVESTMENTS WILL "STIMULATE ECONOMIC GROWTH" AS CLAIMED BY DUKE IN ITS APRIL 12, 2017 PRESS RELEASE?

A. No. When Duke makes statements about "investments" in North Carolina, it is important to note that Duke expects to recover those investments from captive consumers in the State and to earn a handsome return on those same investments. Duke's discussion about economic growth from grid investments is a one-sided story because Duke fails to mention the economic harm to consumers due to the high costs of Duke's proposed grid updates.

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[12] Final Order in Docket No. E-22, Sub 532, p. 104.

This Commission need only look to our neighbors in South Carolina to see an example of the perils of accepting utility promises of economic growth via large plant investments. The citizens of South Carolina have paid billions of dollars in higher rates, received little economic growth, and will likely never receive a single kWh of production from the now-failed Summer nuclear plant.

In the wake of the failed nuclear plant, newspapers in South Carolina have done an excellent job of analyzing utility regulation and how utilities have been shifting risk onto consumers, as is now being requested by Duke in this proceeding. One article, in particular, is well worth reading by the Commission. On December 10, 2017, The Charleston Post and Courier published an article entitled, "Power Failure: How utilities across the U.S. changed the rules to make big bets with your money." I have attached that article in Appendix B and urge the Commission to read it in its entirety in deciding the fate of Duke's GRR request in this proceeding as the framework for the GRR is eerily familiar with failed utility projects in other states.

Q. PLEASE DESCRIBE THE FINDINGS OF THE POST AND COURIER SERIES OF ARTICLES.

A. For the article, The Post and Courier dedicated a team of reporters that interviewed more than 50 industry individuals and painstakingly reviewed tens of thousands of pages of documents in multiple states.

The article begins by quoting executives at SCANA, the Southern Company, and Florida Power and Light that were gushing about the "successes" of their ongoing construction projects. The article then goes on to state:

> They should have said "thank you," because money they torched on these and other power plants wasn't theirs.
>
> It was yours.

> Over the past decade, state legislatures across the country rewrote rule books for how power companies pay for new power plants, shifting financial risks away from electric companies to you and everyone else.
>
> This rule change ignited a bonfire of risky spending — $40 billion so far on new power plants and upgrades, a Post and Courier investigation found.
>
> Flush with your cash, utilities tried to build plants with unproven technology; they launched projects with unfinished designs and unrealistic budgets; they misled regulators and the public with schedules that promised bogus completion dates; they hid damning reports from investors and the public; they tried to silence critics and whistleblowers.
>
> Then, when delays and cost overruns couldn't be ignored, they asked state regulators to charge you more for their failures.
>
> And what happened to these high-stakes gamblers?
>
> Over the past five years, executive teams of six utilities that bet on these plants won $520 million in salaries, bonuses and other personal compensation, the newspaper found.

The article goes on to state the following summary of the newspaper's findings:

> The result is a tale about power — political and electric. It's about how an industry helped change rules so it could make big bets with your money.

The article further states:

> These rule changes largely flew under the public's radar as industry insiders worked elbow-to-elbow with lawmakers to craft laws with obscure acronyms and benign language such as "advanced cost recovery."

It is important to note that, in the current case, DEC is asking the Commission for its own "advanced cost recovery" in the form of a GRRR to require ratepayer to foot the bill for a $13 billion investment in "grid modernization."

In the wake of the South Carolina Summer nuclear fiasco, the Kemper gasification mess, and the other utility boondoggles mentioned in this very well written Post and Courier article, I am stunned that Duke management tried to enact the GRRR at the NC Legislature, where it failed. Undeterred, however, Duke is now before this Commission requesting upfront ratemaking treatment for its GRRR. Perhaps DEC management is hoping state legislators and this Commission have not been following actions in these other southeastern states.

Clearly, those that do not learn from history are bound to repeat it.

Q. WAS THE LEE NUCLEAR PLANT MENTIONED IN THE POST AND COURIER ARTICLE?

A. Not specifically, but the article did note that North Carolina and Florida ratepayers did pay billions of dollars for plants that never were constructed. I presume the plant to which the newspaper is referring is the Lee Nuclear plant that Duke, in this current proceeding, is seeking cost recovery exceeding $500 million when it was authorized to spend up to ONLY $120 million.

Just as is the case with the Summer Nuclear Plant in South Carolina, Duke's GRRR shifts risk to consumers, drives up electric rates, and does not provide guaranteed benefits commensurate with the $13 BILLION price tag.

Q. IS DUKE WILLING TO GUARANTEE CONSUMERS WILL REALIZE A REDUCTION IN OUTAGES FROM ITS PROJECT GRIM INVESTMENTS?

A. No. In a data request, CUCA asked if DEC could provide any guarantee that Project GRIM would reduce outages. Duke opined what it "expects" the outage savings will be, but the Company categorically stated that it could not offer any assurances of such.[13]

Duke's unwillingness to offer any assurances for improved grid reliability is like an auto manufacturer asking you to buy an expensive new car without any assurance that the car will even run.

SCANA and Santee Cooper spent over $8 billion in plant that will likely never benefit consumers in South Carolina. Duke's Project GRIM investment between North Carolina and South Carolina is $13 billion, more than 50% larger than the failed investment in the Summer nuclear plant. A quick examination of the news media outlets in South Carolina will show an unprecedented level of anger at the failure of a very expensive plant investment. It is wise for North Carolina to proceed very, very slowly on this issue or else we risk suffering the same fate now being endured by the good folks in South Carolina.

Q. IS RELIABILITY IMPORTANT TO MANUFACTURERS?

A. Absolutely. When a power outage occurs, manufacturers typically go off-line and lose product. Even a short outage can result in tens of thousands or hundreds of thousands of dollars in product losses. However, there is a limit to the level of higher rates manufacturers can support to offset POTENTIAL reductions in outages. The cost increases found in Table 5 above show a 20 MW customer would see an increase of $14.5 million to pay for Duke's planned "Project GRIM" costs. Such a cost increase would threaten the on-going viability of manufacturers to continue to operate in this State, thereby putting many North Carolina jobs at risk.

[13] DEC Response to CUCA DR 2-6.

Q. HOW DOES DUKE'S PLANS TO SPEND $13 BILLION FOR "PROJECT GRIM" IN THE CAROLINAS COMPARE TO OTHER GRID INVESTMENT PLANS FOR UTILITIES ACROSS THE COUNTRY?

A. Duke's plan to spend $10 billion in North Carolina on "Project GRIM" is more expensive than grid update plans from across the country. In a CUCA data request, I asked Duke if it had compared its estimated Project GRIM expenses of $10 billion to grid expenditures of other utilities. Below is Duke's response to CUCA's data request

DEC Response to CUCA DR 1-6

> No formal comparison was developed relative to grid investments proposed by other utilities. However, the Company did collaborate with other similar-sized utilities, including Dominion Energy, Inc. and Duke Energy operating companies in other jurisdictions performing similar work to benchmark operational and technology concepts and lessons learned, as well as scope and costs. These lessons learned and benchmarking discussions were used as input in the development of DEC's grid investment plan.
>
> The attached slide "Grid CAPEX.pdf" outlines research performed in early 2015 on future grid capital expenditures by other large utilities.

I opened the above-stated Grid Capex.pdf file and compiled the following cost comparison.

Table 5: Grid Capex

Utility	GRIM Forecasts
	(billions)
FPL	$3.50
Southern	$4.00
Dominion	$7.00
AEP	$8.00
SDG&E	$5.00

S. Cal. Edison	$12.00
Duke - Carolinas	$13.00

The concern with the above comparison, as well as any other grid capex comparison is making sure that we are comparing apples to apples and oranges to oranges. What Duke considers to be a grid investment update may very well be considered a routine T&D capex for another utility. Based upon my review of grid capex from around the country, there is no clear definition for grid investment modernization. Furthermore, the values are found in Table 5 above are based on different timeframes thereby making a comparison difficult.

Q. HOW ARE OTHER STATES HANDLING GRID "MODERNIZATION" INVESTMENT EXPENSES?

A. Less than five miles from the NC Utilities Commission is the NC Clean Energy Technology Center (NCCETC) housed at NC State University. The NCCETC publishes a quarterly report entitled "The 50 State of Grid Modernization." In my review of grid expense reports from across the country, this NCCETC report is the most up-to-date and complete authoritative report on grid actions around the country. Below is a summary of the report taken from the NCCETC's website.

The report finds that 36 states and the District of Columbia took some type of action on grid modernization during Q2 2017 (see figure below). Specifically, the report finds that:

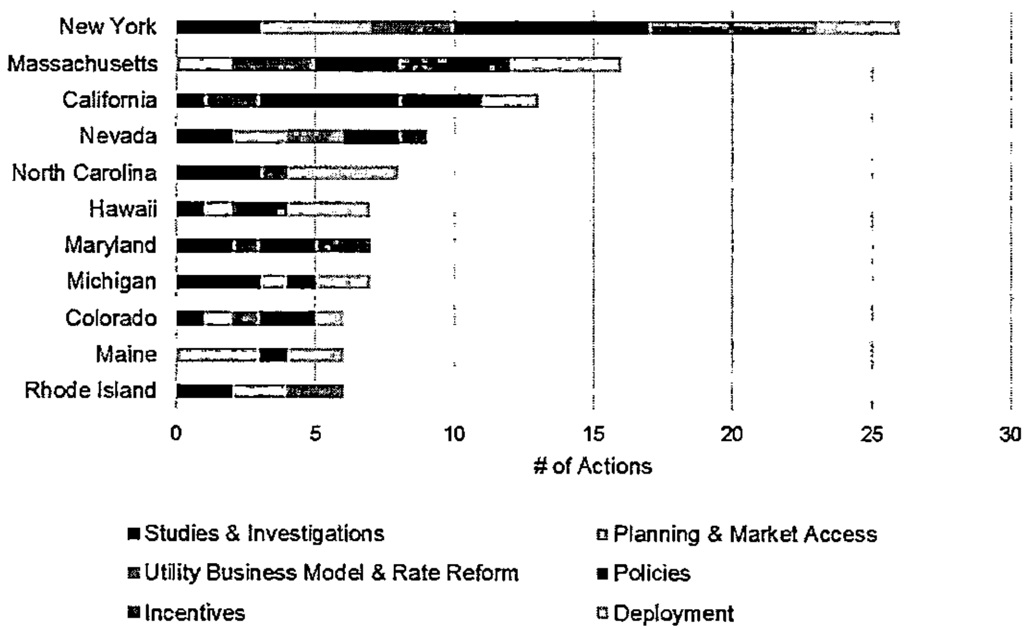
- state or utility proposals in 20 states to implement demand response programs or deploy advanced metering infrastructure, smart grid technologies, microgrids, or energy storage were pending or decided.

- o 19 states plus D.C. took action to study or investigate grid modernization, energy storage, demand response, or rate reform.

- 19 states considered or enacted changes to policies related to grid modernization, including energy storage targets and clean peak standards.
- 15 states considered changes to utility planning processes or rules enabling market access.
- 14 states took action related to utility business model or rate reforms.
- 11 states considered adopting new incentives or making changes to existing incentives for energy storage and microgrids.[14]

The NCCETC report goes on to note that North Carolina is already one of the most active states in terms of grid expenses. Below is a chart from the Q2 edition of "The 50 State of Grid Modernization."

Chart 3: Most Active States of Q2 2017



Source: The 50 States of Grid Modernization: Q2 2017 Quarterly Report, 11

Below is summary of other state actions in regard to grid "modernization" efforts:

<u>Connecticut</u>

[14] https://nccleantech.ncsu.edu/the-50-states-of-grid-modernization-q2-2017-update-report-released-today/

The Connecticut Dept. of Energy and Environmental Protection (DEEP) updated the Connecticut Energy Storage (CES) plan to create a "cheaper, cleaner, more reliable energy future for Connecticut's residents and businesses." (2017 Draft Connecticut Comprehensive Energy Strategy, p. viii).

The draft report states that in 2017, Connecticut energy policy must, amongst other items, "focus on grid modernization, strategic electrification, increasing efficiency, and improving reliability and security" (2017 Draft Connecticut Comprehensive Energy Strategy, p. x).

District of Columbia

On June 12, 2015, the Public Service Commission of the District of Columbia issued an order that opened a proceeding to "identify technologies and policies that can be implemented in the District to modernize the distribution energy delivery system for increased sustainability (MEDSIS); and, in the near-term, to make the distribution energy delivery system more reliable, efficient, cost effective, and interactive." [15]

The MEDSIS Staff actions involved 3 public hearings from October of 2015 to April of 2016 and, in its final report, recommended a pilot project to study the issue further.[16]

The MEDSIS report also studied grid "modernization" efforts in other jurisdictions and concluded the following:

> While something can be learned from the efforts in all of these jurisdictions, Staff has found no grid modernization model that can be imported wholesale. To be successful, the reform path chosen by the Commission must fit the District's unique circumstances; these are just some of the differentiating factors

[15] MEDSIS Staff Report, Jan. 25, 2017, Executive Summary, ii

16 Id, iii

> that Staff believes are important for the Commission to consider as solutions are proposed.[17]

Ohio

The Public Utilities Commission of Ohio also chose to hold public hearings to study grid changes. According to its website:

> The PUCO will kick off PowerForward on April 18, 19 and 20 (2017). The three-day "A Glimpse of the Future" series will feature presentations examining technologies affecting a modern distribution grid; what our future grid could offer consumers; and what technologies are in development to realize such enhancements.[18]

Illinois

Illinois is another state that chose to have a study of grid modernization efforts.

> NextGrid is an approximately 18-month consumer-focused study to address critical issues facing Illinois' electric utility industry in the coming decade and beyond. Managed by the Illinois Commerce Commission, the study will examine the use of new technologies to improve the state's electric grid while minimizing energy costs to consumers. The study will focus on innovation, technological advancements, economic development, environmental considerations and education.[19]

New Hampshire

On July 13, 2015, the New Hampshire Public Service Commission opened a docket to investigate grid modernization in New Hampshire (IR 15-296). The investigation gave public stakeholders an opportunity to learn about grid

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17 Id, iii

18 **https://www.puco.ohio.gov/industry-information/industry-topics/powerforward/**

19 https://nextgrid.illinois.gov/

modernization and how it could be implemented in New Hampshire. The PSC investigation culminated in a final report issued on March 17, 2017.[20]

Hawaii

The Hawaii Public Utilities Commission (PUC) ordered the utilities it regulates to submit reports on grid modernization. The PUC then asked for public comments in a period starting on Aug. 30, 2017 and running through Sept. 13, 2017.[21]

Q. DID YOU FIND ANY CONSISTENCIES AMONGST THE VARIOUS STATE EFFORTS?

A. Yes. The one overriding theme I found in my analysis of various state actions is that of transparency and public involvement. No state regulator that I studied supported a closed process where the public is not involved. Unfortunately, such is not the case in North Carolina as Duke appears not to want public input into its proposed grid "modernization" expenses. In rebuttal testimony in the Duke Energy Progress case, Mr. Bobby Simpson of Duke stated the following:

Q. DID ANY PARTY SUGGEST BEGINNING A SEPARATE PROCEEDING TO CONSIDER GRID INVESTMENT?

> A. Yes. <u>Several witnesses suggested separate proceedings to varying degrees. The Company does not believe that is necessary.</u> I am not aware of any pre-approval process for grid investments in North Carolina like we have for generation investments. From my perspective this is no different from the grid planning we've done for years, it's just that timing and the age of the grid require more investment than we've historically

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[20] Grid Modernization in New Hampshire, Report to the New Hampshire Public Utilities Commission From the Grid Modernization Working Group, Final Report submitted March 20, 2017, p. 3

[21] https://www.hawaiianelectric.com/about-us/our-commitment/investing-in-the-future/grid-modernization-strategy

> had to make. <u>The Company is intentionally being transparent in its plans, both in customer communications and even in discussions and discovery in this case, but the Company does not believe that a separate proceeding is required or advisable.</u>[22] (underline added)

With respect to Mr. Simpson, I **<u>strongly disagree</u>** with his assertion that Duke is being transparent with its plans. In response to CUCA DR 1-7, Duke stated that it had not publicly released the annual costs of its Power/Forward program. Without cost information, Duke is only informing the public of all the positive aspects of its grid plans. The Company has not and appears unwilling to inform the general public that it seeks to raise rates as much as 50% to pay for its grid expansion plan. Telling the consuming public only half the story and then resisting public input is a sure sign that Duke is concerned about customer backlash to its uber-expensive grid plans. Given the fact that 79% of the public opposes a rate hike of 3% or more for Project GRIM, it is easy to see why Duke does not want a public proceeding and public scrutiny of the GRIM costs.

I remind the Commission of one of the findings of the above-mentioned <u>Post and Courier</u> article that stated:

> These rule changes largely flew under the public's radar as industry insiders worked elbow-to-elbow with lawmakers to craft laws with obscure acronyms and benign language such as "advanced cost recovery."

Duke has not disclosed the cost of Project GRIM to consumers nor does the Company want this Commission to open a separate proceeding on Duke's GRRR request. Duke appears to want the GRRR to fly "under the public's radar" as the Company's own polling finds customers are opposed to massive rate hikes for Project GRIM.

[22] Rebuttal Testimony of Bobby Simpson in Docket No. E-2, Sub 1142, 17

Q. DO YOU AGREE THE COMMISSION WILL MAINTAIN FULL REGULATORY REVIEW OF DUKE'S PLANNED GRID INVESTMENTS IN THE ANNUAL TRUE-UP PROCESS?

A. Not completely. There is an old saying that goes:

It is better to beg forgiveness than ask permission

As evidenced by the above statement of Mr. Simpson, Duke does not want the Commission and the general public to peek behind the curtain at its grid investment plans. Instead, Duke appears to support a blank check cost approach. If the Commission approves Duke's request in this rate case for the GRRR, Duke will make its grid modifications and then file annual cost data to support and seek full cost-recovery for those modifications via GRRR rider adjustments. During these annual update proceedings, the burden of proof as to the reasonableness of those investments ostensibly shifts to consumers. Duke will presume the Commission will approve all its past investments and will seek rate recovery thereof. As a result, the consumer, not the utility, will have the burden of proof that past expenses were not reasonable or prudent. Such a burden is too much to ask of the Public Staff and other intervenors. Duke should be required to ask for permission to commit ratepayer monies for grid projects before-the-fact much the same way that the Company must obtain permission to build generating plants. It is vastly harder for consumers to argue prudence after the utility has already spent the money.

Evidence of my concern regarding the shifting of the burden of proof can also be seen in the fact that CEO Lynn Good has threatened litigation over coal ash if this Commission does not grant full recovery of its costs. [23] Duke's

[23] "Duke Energy CEO says question of who pays coal-ash costs could end up in court", Charlotte Business Journal, Nov, 3, 2017

management presumes Duke has complete and absolute right to coal ash clean-up cost recovery. Such a presumption puts consumer that must pay the bills and their advocates in a very difficult position in arguing against costs that have already been spent.

Another example of the shifting burden of proof is in the current case where Duke is seeking cost recovery for the entire amount of Lee nuclear plant development costs exceeding $500 million when this Commission authorized it to spend up to only $120 million on the project. If Duke had sought permission to spend over $120 million on the Lee plant, the Commission could have analyzed the request in advance of the expenditures. Instead, Duke is now before the Commission seeking recovery of the extra $400 million after-the-fact. The Lee nuclear plant scenario is a clear example of taking the utility monopoly posture that...**it is better to beg forgiveness than to ask for permission.**

Q. DO YOU HAVE A RECOMMENDATION TO THIS COMMISSION IN REGARD TO DUKE'S PLANNED TRANSMISSION AND DISTRIBUTION INVESTMENT PLANS (PROJECT GRIM)?

A. Yes. As has been done in numerous other states, I recommend the Commission open a separate public docket to investigate the need for Duke's proposed grid investments. In that docket, I suggest the Commission examine the following issues, among others, involving grid updates for DEC:

1. Is the Duke plan for grid investments needed for reliability purposes?;
2. How many hours of reduction of outages can DEC customers receive with the implementation of Project GRIM?;
3. How much will the outage improvement, assuming it occurs, cost consumers?
4. Is Duke's grid update plan cost-effective?;
5. How are other states handling grid investment updates?;
6. What are the lessons learned from other states?;

7. How will the State's renewable energy industry be impacted by DEC's Project GRIM?; and
8. How will the rate increases expected under Duke's plan affect the State's economy?

Issue 4 above is noteworthy. To be specific, Duke's Project GRIM is going to cost residential consumers almost $4,000. How many hours of outage reductions will consumers receive for their $4,000? Are consumers willing to pay $4,000 for this extra outage reduction ON TOP of the amount they are already paying in current rates for O&M on the grid?

Furthermore, the price of batteries continues to fall. A 5-kW Tesla Powerwall, for example, costs $8,000 installed.[24] It is illogical to spend $4,000 with Duke and still endure outage reductions when the consumer could spend $8,000 and be assured of almost no interruptions (and Duke would not be charging a rate of return on the battery, since it would be owned by the customer).

If the Commission chooses not to open a separate proceeding on Project GRIM, I recommend the Commission rule that Duke's Grid Modernization costs and the establishment of a Grid Modernization Rider are issues that require study and direction from the North Carolina General Assembly. In fact, the General Assembly, pursuant to legislation (SB-619 – entitled JCLEP Study Grid Modernization) introduced during the 2017 session, envisioned that the Joint Legislative Commission on Energy Policy (JLCEP) should complete a comprehensive study of known and measurable costs and benefits of grid modernization investment by IOUs. The study shall include an analysis of the need to enhance and modernize the electrical transmission and distribution grid to ensure the grid is resilient, secure, capable of meeting future demand growth

[24] https://www.energysage.com/solar/solar-energy-storage/tesla-powerwall-home-battery/

and able to integrate new technologies. The JLCEP would complete the study and report its findings and recommendations to the General Assembly by March 1, 2018. The JLCEP would be allotted $300,000 to conduct the study and hire consultants to assist therewith.

Although CUCA was supportive of SB-619, we believe the study must be performed by a qualified, <u>independent, unbiased</u> consultant without undue influence from the investor-owned utilities. We believe that it would be prudent for the consultant to include in the comprehensive report a listing of the specific grid modernization improvements that the IOUs have made during the past five years and the associated expenditures. It is prudent to look behind so that we can better look and plan ahead for which grid investments are truly needed and the appropriate timeframe for making those upgrades. Before asking ratepayers to dig deep into their wallets to pay an extra $10 BILLION to Duke, it is critical to ensure the nature and scope of needed investment.

Q. HAS DUKE PERFORMED AN ECONOMIC ANALYSIS OF ITS PROPOSED GRID "MODERNIZATION" EFFORTS?

A. Duke has retained the services of EY Consulting to study the impacts of its grid "modernization" efforts, but the EY study results are highly questionable for several reasons.

First, EY is not an independent consulting firm. EY has a longstanding relationship with Duke. Over the past five years, Duke has paid EY over $122 million in fees.[25] Duke paid EY $185,000 for the study.[26]

Secondly, while EY attempted to quantify how Duke's $10 billion expenditure would benefit the economy, it seemingly gave only token attention to the

[25] DEC Response to CUCA DR 1-4.

[26] DEC Response to CUCA DR 1-3

increase in power rates that will befall consumers with Duke's Project GRIM. Below is the only mention of rate increases found in the EY report:

> These benefits will be partially offset by increased electricity rates paid by Duke Energy's customers to support the program investment. Duke Energy estimates that average retail electricity rates for North Carolina customers will increase by approximately 20% by 2026, relative to current rates. The rate increases grow along with investment and track with benefits over the period. The annual costs (incremental rate increases) will range from $62 million in 2018 to $1.44 billion by 2028.[27]

The EY also states in the report that:

> While customer rates will increase as a result of the capital spending, the economic benefits are estimated to exceed these costs. [28]

The EY report goes on to state that the econometric model upon which it based its analysis has several limiting issues, <u>one of which is that 50% of the underlying data is more than 15 years old as of 2015</u>. [29]

3. Job Retention Rider

Q. DO YOU AGREE WITH DUKE'S PROPOSAL TO SOCIALIZE THE JRT COSTS?

A. Yes, but only because the alternative is even worse for residential and small commercial consumers. If DEC continues to lose industrial load, the fixed costs

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[27] North Carolina impacts of Duke Energy's Power/Forward grid improvement program, Prepared for Duke Energy by EY Quantitative Economics and Statistics (QUEST), November 2017, 19

[28] North Carolina impacts of Duke Energy's Power/Forward grid improvement program, Prepared for Duke Energy by EY Quantitative Economics and Statistics (QUEST), November 2017, 25

[29] North Carolina impacts of Duke Energy's Power/Forward grid improvement program, Prepared for Duke Energy by EY Quantitative Economics and Statistics (QUEST), November 2017, 28

of operating the DEC system will be shifted in even greater amounts to the remaining DEC customers thereby causing rate hikes far greater than the 0.74% as cited by Duke in the JRT application.

Q. DO YOU HAVE AN ESTIMATE OF HOW MUCH RATES WOULD INCREASE TO DUKE CUSTOMERS IF THE COMPANY WERE TO LOSE ITS INDUSTRIAL LOAD?

A. Yes. As I have stated previously, Duke's industrial load is flat and its rates are increasing. There is no doubt that industrial consumers that have the option of operating plants in other states are looking to exercise those rights and move production. If such a situation occurs and Duke loses its industrial load, I have calculated the rates for remaining customers to increase by over 16% annually.

Table 6: Rate Impact with Loss of Industrial Consumers

	Total Company	Rates 21, 29, 40, 43
Adjusted Revenues [1]	$4,991,300	$1,280,798
Less:		
Energy Related O&M [1]	$1,387,955	$471,171
Gross Margin - Revenues less Energy Related O&M	$3,603,345	$809,627
	Rate Hike if Industrial Customers left DEC	16.22%

[1] DEC-filed SCP Cost of Service Study, Form e-1, Item 45A

This rate hike does NOT include the Company's GRRR expenditures, which would further increase rates for the remaining customers.

The situation of socializing the Duke costs reminds me of the old Fram oil filter commercial in the 1970s where the tag line was "pay me now or pay me later."

For those that do not remember the commercial, or are too young to have seen it in the first place, below is a link to the commercial.

https://www.youtube.com/watch?v=Ij1yDpfZI8Q

The corollary here is that DEC residential customers can pay a little bit higher in rates now or run the risk of paying rates that are a lot higher down the road.

4. Coal Ash Costs

Q. MR. O'DONNELL, PLEASE EXPLAIN THE BACKGROUND THAT HAS LED DEC TO REQUEST RECOVERY OF $200 MILLION OF COAL ASH EXPENSES IN THIS CASE.

A. On February 2, 2014, (DEC) spilled a large amount of coal ash in the Dan River. This spill made the national press. The Dan River spill will be cleaned up with Duke stockholder funds. Information exposed in the Duke federal plea deal, which is described below, revealed that on two separate occasions, Duke engineers at the Dan River plant requested a paltry amount of budget funding to pay for video equipment to scope the pipe that later failed. Duke engineers were denied the request. [30]

On September, 2014, in response to the Dan River spill, the NC Legislature passed the Coal Ash Management Act (CAMA) that required the closure of existing coal ash ponds as well as conversion from wet ash to dry ash handling. CAMA was the first such coal ash management law in the United States. This initial legislation required basins at four "high risk" Duke plants to be closed by 2019. Intermediate risk plant basins were to be closed by 2024 and low risk

30 United States District Court for Eastern District of North Carolina, Case Nos. 5:15-CR-62-H, 5:15-CR-67-G, 5:15-CR-68-H, ordering paragraphs 69-80

basins were to be closed by 2029. Initially, Duke set aside $3.6 billion in an Asset Retirement Obligation (ARO) but that ARO has since grown to $5.2 billion for both DEC and DEP.

On December 19, 2014, the EPA issued the Coal Combustion Residual (CCR) Order that provided minimum national criteria for CCR landfills, CCR surface impoundments, and lateral expansion of coal-fired units. The CCR federal rule was designated as "self-implementing," meaning that Duke was not under any requirement to act UNLESS it is sued by a state or other entity and loses that lawsuit.

On May 14, 2015, Duke (DEC, DEP and Duke Energy Business Services) pled guilty to nine violations of the Clean Water Act and was fined $102 million by the federal courts[31.] Below are some of the issues to which Duke admitted guilt:

- From at least January 1, 2012, Duke Energy Carolinas and Duke Energy Business services failed to properly maintain and inspect the two storm water pipes underneath the primary coal ash basis at the Dan River Steam Station in Eden, North Carolina. On February 2, 2014, one of those pipes failed, resulting in the discharge of approximately 27 million gallons of coal ash wastewater and between 30,000 and 39,000 tons of coal ash into the Dan River[32]
- Duke Energy Progress and Duke Energy Business Services also failed to maintain the riser structures in two of the coal ash basins at the Cape Fear Steam Electric Plant, resulting in the unauthorized discharges of

31 United States DE Ct. of Justice press release, May 14, 2015, 1

32 United States District Court for Eastern District of North Carolina, Case Nos. 5:15-CR-62-H, 5:15-CR-67-G, 5:15-CR-68-H, 2

leaking coal ash wastewater into the Cape Fear River.[33]

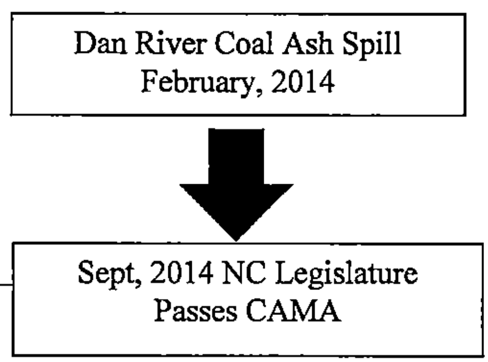
- Additionally, Duke Energy Carolinas and Duke Energy Progress's coal combustion facilities throughout North Carolina allowed unauthorized discharges of pollutants from coal ash basins via "seeps" into adjacent waters of the United States.[34]
- The Defendants' conduct violated the Federal Water Control Act (commonly referred to as the "Clean Water Act," or "CWA"). 33.U.S.C. 1251. [35]

Below is what an official with the United States Environmental Protection Agency said about Duke officials and coal ash:

> "Duke management failed in their responsibility to the people of North Carolina. Their criminal negligence is what caused this disaster," said Cynthia Giles, assistant administrator for enforcement for the U.S. Environmental Protection Agency. [36]

Chart no. 4 below shows the milestone dates for the Duke coal ash situation from the spill at Dan River to the current rate case recovery request.

Chart 4: Duke Coal Ash Timeline

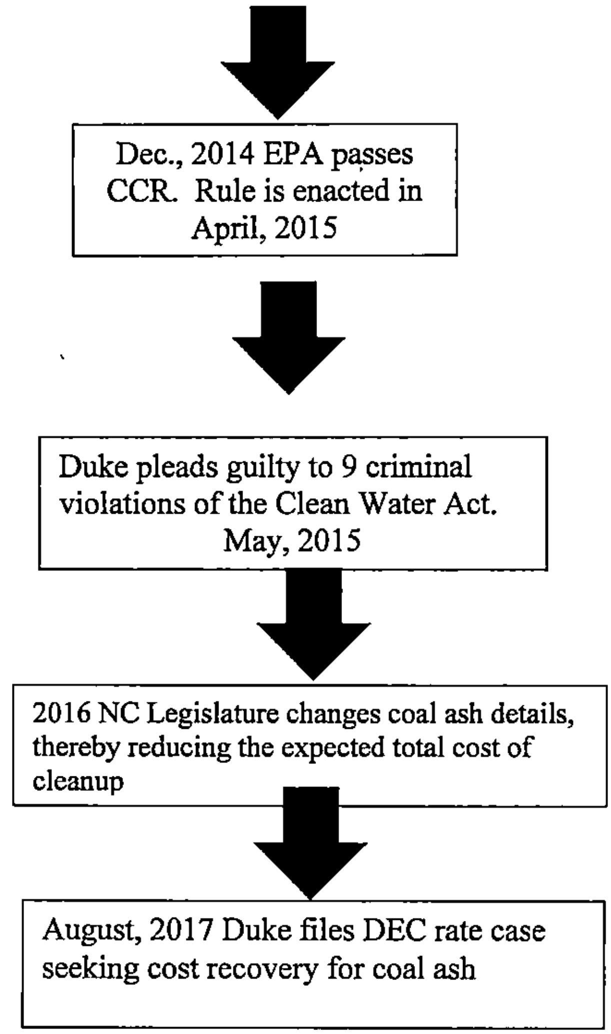


33 Id at 3

34 Id at 3

35 Id at 4

36 http://www.wral.com/duke-energy-pleads-guilty-to-environmental-charges-linked-to-coal-ash-spill-leaks/14645414/)



Q. DOES DUKE BELIEVE IT IS ENTITLED TO 100% RECOVERY OF ALL COAL ASH EXPENSES?

A. Yes, with the exception of the Dan River spill clean-up costs and fines. Duke maintains that its coal ash expenses are being incurred as a normal course of its business operations and, as such, ratepayers should pay these costs entirely.

Q. DO YOU BELIEVE DUKE IS RESPONSBLE FOR ANY OF THE COAL ASH COSTS REQUESTED BY THE COMPANY IN THIS CASE?

A. Yes. Duke should be able to recover <u>only</u> the "normal course of business" coal ash clean-up costs. The "normal" costs of cleanup are only those that would have occurred under the EPAs Coal Combustion Residual (CCR) rule. However, any costs over-and-above the CCR costs, such as the higher CAMA-related clean-up costs, are clearly the result of Duke mismanagement of its coal ash ponds and should not be recovered from ratepayers.

Q. WHY DO YOU BELIEVE DUKE STOCKHOLDERS SHOULD ABSORB ALL COSTS OVER CCR-MANDATED COSTS?

A. The Dan River spill was clearly a catastrophic event for neighbors of the coal plant and for entities downriver from the plant. The press wrote numerous articles and CBS sent a 60 Minutes crew to interview Duke CEO Lynn Good. State legislators in North Carolina were outraged and ordered Duke to clean up its coal ash ponds when the legislature passed the Coal Ash Management Act (CAMA) just a mere seven months after the Dan River spill.

It is clear that the Dan River spill was caused by mismanagement by Duke executives. As noted previously, Duke engineers at the Dan River plant asked for video equipment on two occasions to scope the lines that ultimately failed. Duke executives denied both requests and the line ultimately failed spilling 39,000 tons of coal ash into the Dan River. If the video equipment had been purchased and the line scoped, it is likely the problem in the line would have been discovered and repaired or replaced, the spill would not have occurred, and CAMA would not have been created and signed into law. To the extent that the CAMA-related costs are in excess of the EPA-mandated CCR costs, Duke stockholders should absorb those incremental costs due to the mismanagement by Duke executives.

Q. CAN YOU PROVIDE ANY EVIDENCE THAT THE CAMA LEGISLATION WAS PROMPTED BY THE DAN RIVER SPILL?

A. Yes. Below is a portion of an article from the local Raleigh television station's website, wral.com, that shows CAMA was caused by the Dan River spill.

> According to one of Duke Energy's top leaders, North Carolina's 2014 coal ash legislation didn't necessarily result from a company ash spill in the Dan River.
>
> Federal coal ash rules were already being drafted at the time, and it's possible, Duke state President David Fountain testified Monday during a rate increase hearing, that the North Carolina General Assembly would have passed its law anyway.
>
> Twice, Sierra Club attorney Matthew Quinn asked Fountain whether the law was motivated, or partially motivated, by a spill that turned parts of the river gray.
>
> "I really can't admit that," Fountain replied.
>
> State Rep. Pricey Harrison, D-Guilford, who saw her push for coal ash regulations gain traction only after the spill, scoffed at this Monday evening. When the bill passed in 2014, Senate negotiator Tom Apodaca specifically said that, "When I saw the Dan River thing, I said, 'We've got to do something.'" State Rep. Chuck McGrady, R-Henderson, who negotiated the bill for the House, told the Associated Press that, "unfortunately, sometimes we wait until we have a really big problem before we address it."
>
> "It makes sense for (Fountain) to say that, but he is flat wrong," Harrison said Monday. [37]

Q. CAN YOU DETERMINE A DIVIDING LINE BETWEEN CAMA AND CCR COSTS?

A. Yes. First, it is important to note that only North Carolina utilities are subject to the requirements of CAMA. To my knowledge, no other state has enacted a state-specific law mandating the clean-up of coal ash ponds. Sadly, NC is unique and, if the CAMA requirements are more stringent than the CCR requirements, the coal ash costs recorded as asset retirement obligations (AROs)

37 http://www.wral.com/seeking-rate-increase-duke-energy-dodges-link-between-coal-ash-spill-and-coal-ash-bill/17145054/

established by the Duke subsidiaries would be higher than the AROs established by utilities around the country.

Q. DID YOU MAKE THIS ARO COMPARISON OF COAL ASH COSTS OF THE DUKE SUBSIDIARIES RELATIVE TO UTILITIES ACROSS THE COUNTRY?

A. Yes.

Q. PLEASE DESCRIBE HOW YOU MADE THIS COMPARISON.

A. Using data obtained from SNL Financial and the Excel software, I extracted AROs on the books of utilities from across the country. However, upon receipt of the extracted data, I realized the AROs were not segregated for coal ash costs only. As a result, I researched the 2016 individual financial statements of the 25 utilities with the highest AROs extracted from SNL Financial to segregate the coal ash AROs from other items not related to coal ash. The results of this analysis can be seen in Table 7 below.

Table 7: Coal Ash AROs

Ranking	Company Name	Total Coal Ash AROs (000's)[38]
1	Duke Energy Progress, LLC	$2,228,000
2	Duke Energy Carolinas, LLC	$2,032,000
3	Georgia Power Company	$1,291,000
4	Duke Energy Indiana, LLC	$866,242
5	Virginia Electric and Power Company	$583,000
6	Kansas City Power & Light Company	$278,043
7	PacifiCorp	$214,786
8	DTE Electric Company	$212,000
9	Alabama Power Company	$199,000
10	Dayton Power and Light Company	$135,159
11	Mississippi Power Company	$128,000
12	Appalachian Power Company	$127,098

[38] Raw data taken from snl.com

13	ALLETE (Minnesota Power)	$93,304
14	Southwestern Electric Power Company	$83,454
15	Nevada Power Company	$82,938
16	Kansas Gas and Electric Company	$74,300
17	Oklahoma Gas and Electric Company	$69,576
18	Kentucky Power Company	$62,994
19	Arizona Public Service Company	$56,000
20	Public Service Company of Oklahoma	$53,413
21	Kentucky Utilities Company	$49,000
22	Tampa Electric Company	$44,879
23	KCP&L Greater Missouri Operations Company	$37,998
24	Monongahela Power Company	$37,509
25	Tucson Electric Power Company	$32,655
26	Gulf Power Company	$29,000
27	Southwestern Public Service Company	$28,663
28	Westar Energy (KPL)	$28,018
29	Idaho Power Co.	$26,257
30	Public Service Company of New Hampshire	$23,529
31	Empire District Electric Company	$23,517
32	Portland General Electric Company	$23,000
33	Duke Energy Florida, LLC	$19,000
34	Indiana Michigan Power Company	$18,079
35	Public Service Company of New Mexico	$17,724
36	Entergy Mississippi, Inc.	$8,722
37	Otter Tail Power Company	$8,341
38	Cleco Power LLC	$6,933
39	Wheeling Power Company	$6,848
40	Entergy Texas, Inc.	$6,470
41	Ohio Power Company	$1,654

As can be seen in the table above, the Duke AROs specific to coal ash are MUCH greater than the coal ash AROs from other utilities. On the surface, this table strongly implies that the North Carolina CAMA legislation is much more stringent than the CCR requirements.

Q. DID YOU DO ANY FURTHER ANALYSIS ON THE COAL ASH AROs AS STATED BY DUKE RELATIVE TO OTHER UTILITIES?

A. Yes. I recognize that Duke may have a greater amount of coal generation relative to other utilities in the country. To normalize for the difference in coal ash generation across the country, I also examined the established AROs relative to the amount of coal ash that is present for each utility in the above-stated table. To be specific, I calculated a ratio of coal ash AROs relative to the MWHs of coal generation for each utility. I determined the amount of MWHs of historical coal generation by multiplying the amount of coal generation of each utility by the average age of the utility's coal generation fleet by an assumed capacity factor of 65%. Lastly, I sorted the ratio of coal ash AROs by MWHs of coal generation to calculate a ratio for each utility. The results of this analysis can be seen in Table 8 below and the details of the calculations can be seen in Exhibit KWO-5.

Table 8: Coal Ash ARO per MWH of Generation

Ranking	Utility	Calculated ARO per MWH of Gen.
1	Duke Energy Progress, LLC	$0.002436
2	Nevada Power Company	$0.001274
3	Duke Energy Carolinas, LLC	$0.001166
4	Mississippi Power Company	$0.001079
5	Duke Energy Indiana, LLC	$0.000829
6	Georgia Power Company	$0.000815
7	Virginia Electric and Power Company	$0.000603
8	Kansas City Power & Light Company	$0.000464
9	Public Service Company of Oklahoma	$0.000433
10	ALLETE (Minnesota Power)	$0.000397
11	Kentucky Power Company	$0.000295
12	Empire District Electric Company	$0.000287
13	Kansas Gas and Electric Company	$0.000267
14	Dayton Power and Light Company	$0.000252
15	Southwestern Electric Power Company	$0.000178
16	KCP&L Greater Missouri Operations Company	$0.000172
17	Alabama Power Company	$0.000145
18	Public Service Company of New Hampshire	$0.000139
19	PacifiCorp	$0.000130
20	Portland General Electric Company	$0.000130
21	DTE Electric Company	$0.000118

22	Oklahoma Gas and Electric Company	$0.000116
23	Arizona Public Service Company	$0.000115
24	Entergy Texas, Inc.	$0.000111
25	Appalachian Power Company	$0.000110
26	Tampa Electric Company	$0.000103
27	Idaho Power Co.	$0.000103
28	Entergy Mississippi, Inc.	$0.000100
29	Tucson Electric Power Company	$0.000092
30	Public Service Company of New Mexico	$0.000071
31	Otter Tail Power Company	$0.000064
32	Gulf Power Company	$0.000064
33	Southwestern Public Service Company	$0.000063
34	Indiana Michigan Power Company	$0.000063
35	Kentucky Utilities Company	$0.000060
36	Westar Energy (KPL)	$0.000057
37	Cleco Power LLC	$0.000055
38	Monongahela Power Company	$0.000045
39	Duke Energy Florida, LLC	$0.000034
40	Wheeling Power Company	$0.000032
41	Ohio Power Company	$0.000010

In the above table, Nevada Power only has a coal ash ARO of $82.9 million as compared to the DEP coal ash ARO of $2.2 billion and the DEC coal ash ARO of $2.0 billion. If we eliminate Nevada Power from the list due to the company's relatively small ARO size, DEC and DEP would have the highest amount of coal ash AROs for its associated estimated amount of coal ash generation.

Q. HOW DO DEC AND DEC COMPARE TO NEIGHBORING UTILITIES THAT OPERATE IN SIMILAR GEOGRAPHIC CLIMATES?

A. In Table 9 below I have provided a comparison of how DEC and DEP compare to neighboring utilities.

Table 9: Coal Ash ARO per MWH of Generation

Neighboring Utilities	ARO per MWH of Gen.

Mississippi Power Company	$0.001079
Georgia Power Company	$0.000815
Virginia Electric and Power Company	$0.000603
Kentucky Power Company	$0.000295
Alabama Power Company	$0.000145
Appalachian Power Company	$0.000110
Average	**$0.000508**
Duke Energy Progress, LLC	**$0.002436**
Duke Energy Carolinas, LLC	**$0.001166**

The results as found in Table 9 above show that, relative to its neighbors, DEC and DEP costs are significantly out of line. The mere fact that the DEC and DEP costs are two-times to almost five-times greater than the average ratio of coal ash to MWH of coal generation seen in other states is prima facie evidence that CAMA-related costs are significantly greater than CCR-related costs.

Q. DO YOU AGREE WITH DUKE'S ARGUMENT THAT YOUR COMPARISON OF THE FINANCIAL COSTS OF THE COAL ASH AROs IS AN INCORRECT COMPARISON?

A. No. I am aware that Duke made this claim in the DEP case, but they offered no evidence to support the claim. I do recognize that each situation is "unique" by itself; however, when you sum up the variations over time, there is no evidence to suggest that Duke's coal ash situation is significantly different from that of utilities across the country and, particularly, that Duke's situation is significantly different from that of utilities in neighboring States.

Again, the burden of proof in this case lies with Duke. The Company has failed to provide any evidence to counter my argument that its mismanagement led to excessive costs associated with its coal ash cleanup. Duke could have, and should have, taken my analysis apart bit-by-bit if it truly felt my financial analysis comparison was in error. The Company chose not to do so, thereby leading credence to the evidence I have presented herein.

Q. IS THE EPA RE-EVALUATING ITS PREVIOUS DECISION IN REGARD TO THE COAL COMBUSTION RESIDUAL RULE?

A. Yes. On Sept. 14, 2017, the EPA indicated that it would grant two legal petitions to re-consider the CCR rule. It is possible that some sort of modification of the CCR may occur.

This decision by the EPA to re-consider the CCR is in direct conflict with Duke Witness Wright who comments on the "ever-tightening environmental regulations" [39]

Q. HOW WOULD A CHANGE IN THE CCR RULE AFFECT DUKE'S ARGUMENT FOR COST RECOVERY OF COAL ASH EXPENSES?

A. Duke has attempted to make the argument that the CCR rule and CAMA were largely duplicative, so consumers should pay for coal ash since the establishment of the CCR negates CAMA which was established due to the Dan River spill. If the CCR rule is modified, diminished or eliminated, Duke's argument is largely negated. While I have presented testimony in this case that shows the incremental cost of CAMA over CCR, the elimination or dilution of CCR will move the dividing line between the two rules even more so against Duke's argument that consumers should pay for the entirety of coal ash expenses.

Q. DO YOU HAVE A RECOMMENDATION TO THIS COMMISSION IN REGARD TO THE AMOUNT OF COAL ASH EXPENSES IT SHOULD DISALLOW IN THIS CASE?

A. Yes, but I must first preface my recommendation with two acknowledgements.

[39] Wright pre-filed testimony in E-2, Sub 1142, 24

First, the analysis I have done in this case is a pure financial analysis. As with any financial analysis, there are strengths/weaknesses and assumptions built into the analysis I have presented. I recognize the Commission must make a decision in this case based on the facts contained in the record of this case. I have presented the Commission with a detailed financial analysis comparing the DEC coal ash costs relative to the country as a whole and, specifically, its neighbors. Second, **Duke is the petitioner in this case and its testimony is devoid of any similar financial analysis**. Duke has the burden of proof in this case and, yet, it has failed to offer up any evidence its costs were appropriate in comparison to other similar utilities. Contrary to Duke, I have at least attempted to give the Commission evidence, specific financial evidence, for its use in deciding a multi-billion dollar issue that affects all of Duke's North Carolina customers.

With the above acknowledgements, I recommend the Commission disallow 75% of Duke's coal ash cost recovery in this case and in all future cases. I base the 75% disallowance on Table 9 above which shows that even a 75% disallowance would still result in consumers in this State paying more for coal ash than those in neighboring states.

75% is a middle ground and recognizes the fact that consumers would have had to pay for some coal ash costs through the EPA's CCR rule whereas, at the same time, gross mismanagement, as evidenced by the Duke federal plea deals, requires stockholders to bear a significant portion of the cleanup costs as well.

Q. IF THE COMMISSION DISAGREES WITH YOU AND ORDERS CONSUMERS TO PAY DUKE THE FULL COST OF THE COAL ASH DISALLOWANCE, DO YOU HAVE ANY FURTHER RECOMMENDATIONS?

A. Yes, this issue of coal ash has been a lightning rod in North Carolina since the Dan River spill. If the Commission chooses to grant Duke's request for full recovery of coal ash expenses, I recommend Duke be required to place as a separate line item on the customers' monthly bills the coal ash recovery surcharge. This transparency would, at the least, provide an incentive to Duke to minimize the cost of the coal ash cleanup for the betterment of the State and its citizens. **Also, if the Commission orders a delayed recovery of costs, I recommend that Duke not be allowed to earn interest on a rate of return on the deferred expenses.**

5. Rate Case Expenses

Q. HAVE YOU REVIEWED THE DEC RATE CASE EXPENSES REQUESTED IN THIS RATE CASE?

A. Yes, I have.

Q. DO YOU AGREE THAT ALL OF THESE RATE CASE EXPENSES SHOULD BE INCLUDED FOR RECOVERY IN THIS RATE CASE?

A. No. I disagree with the rate case expenses for Robert Hevert.

Q. HOW DID DUKE AND THE PUBLIC STAFF FIND AND CONTRACT WITH THEIR RESPECTIVE WITNESSES IN THIS CASE?

A. The Public Staff took competitive bids for rate of return witnesses in the Dominion NC Power rate case of 2016. In the current case, the Public Staff contacted the same consultant and settled on a price that was reasonable by industry standards - $25,000.

Duke, on the other hand, did not engage in any competitive bidding, which implies that consumers would pick up any rate case tab the utility so desire to pass onto consumers. Evidence for this statement can be seen in Duke's response to CUCA data request no. 1-9 from the DEP rate case:

> The Company did not issue RFPs. The Company has established relationships with partners who have a long history of working with the Company, including in rate cases, and who can

> efficiently address unique rate case issues in a cost effective manner. The Company negotiates for discounts where applicable, and also negotiates with experts who can be in high demand in the industry. Moreover, the Company diligently manages the time experts and supporting resources spend on rate case issues to keep downward pressure on bills.[40]

Duke's above statement regarding its definition of "cost effective" is demeaning to the regulatory process in this State. The Company did not issue a RFP, did not get competitive bids, and believes that Mr. Hevert's costs is "cost effective" as compared to the Public Staff witness' cost of $25,000.

Q. WHY ARE YOU FOCUSING ON RATE CASE EXPENSES THAT ARE, OVERALL, A SMALL PART OF THE REVENUE INCREASE REQUEST IN THIS CASE?

A. I understand that the fees of Witnesses Hevert and the other components of the rate case expenses are small in relation to the entire revenue increase request in this case. However, Duke's decision to ask consumers to pay outrageous fees is symptomatic of a larger problem. Duke appears tone deaf when it comes to the economic hardships of its customers as evidence by the excessive rate request.

According to the United States Bureau of Economic Analysis, North Carolina had a per capita personal income (PCPI) of $42,244 in 2016.[41] Based on the rate increases forecasted by Duke for its grid updates, it appears Duke management does not understand how its appetite for every-increasing revenues impacts consumers and the State's economy.

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40 Duke response to CUCA DR 1-9

41 United State Bureau of Economic Analysis, Sept. 26, 2017

6. Return on Equity Analysis

(a) Economic and Policy Guidelines for a Fair Rate of Return

Q. PLEASE BRIEFLY DESCRIBE THE ECONOMIC AND REGULATORY POLICY CONSIDERATIONS YOU HAVE TAKEN INTO ACCOUNT IN DEVELOPING YOUR RECOMMENDATION CONCERNING THE FAIR RATE OF RETURN THAT PUBLIC SERVICE COMPANIES SHOULD HAVE THE OPPORTUNITY TO EARN.

A. The theory of utility regulation assumes that public utilities perform functions that are natural monopolies. Historically, it was believed or assumed that it was more efficient for a single firm to provide a particular utility service than multiple firms. On this basis, state legislatures or commissions assign exclusive franchised territories to public utilities or determine territorial boundaries where disputes arise, in order for these utilities to provide services more efficiently and at the lowest reasonable cost. In exchange for the protection within its monopoly service area, the utility is obligated to provide adequate service at a fair, regulated price.

This naturally raises the question - what constitutes a just and reasonable price? The generally accepted answer is that a prudently managed utility should be allowed to charge prices that allow the utility the opportunity to recover the reasonable and prudent costs of providing utility service and the opportunity to earn a fair rate of return on invested capital. This just and reasonable rate of return on capital should allow the utility, under prudent management, to provide adequate service and attract capital to meet future expansion needs in its service area. Since public utilities are capital-intensive businesses, the cost of capital is a crucial issue for utility companies, their customers, and regulators. If the allowed rate of return is set too high, then consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest in long-lived under-productive rate base items which ratepayers much bear the cost of for decades. If the return is set too low, adequate service is jeopardized because the utility will not be able to raise new or working capital on reasonable terms.

Regulatory law and policy recognize that utilities compete in the market for investor capital. In *Hope Natural Gas*, the U.S. Supreme Court recognized that a utility competes with other firms in the market for investor capital. The Court held that the return to equity owners (or shareholders) of a regulated public utility should be "commensurate" to returns on investments in *other* enterprises whose "*risks* correspond" to those of the utility being examined:

> The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital. [320 U.S. at 603]

Because every equity investor faces a risk-return tradeoff, the issue of risk is an important element in determining the fair rate of return for a utility.

(b) **Cost of Common Equity**

Q. WHAT RETURN ON EQUITY DOES DUKE RECOMMEND THE COMMISSION ADOPT FOR USE IN SETTING ITS RATES IN THIS PROCEEDING?

A. Based on the pre-filed direct testimony of Mr. Hevert, Duke is requesting a return on equity of 10.75%.

Q. HAS ANY OTHER DUKE UTILITY FILED A RATE CASE RECENTLY?

A. Yes, Duke Energy Kentucky filed a rate case on Sept. 1, 2017.

Q. WHAT WAS THE ROE REQUESTED BY DUKE ENERGY KENTUCKY?

A. 10.3%[42]

Q. PLEASE EXPLAIN HOW REGULATORS DETERMINE AN APPROPRIATE RETURN ON EQUITY THAT IS FAIR, JUST, AND REASONABLE TO THE UTILITY AND TO CONSUMERS?

A. Utility regulation recognizes that utilities are entitled to an opportunity to recover the reasonable and prudent costs of providing service, and the opportunity to earn a fair rate of return on the capital invested in providing the regulated service. Utilities obtain capital funding through a combination of borrowing (debt financing) and issuing stock (equity financing). The allowed return on equity ("ROE") is the amount that is determined to be appropriate for the utility's common stockholders to earn. If the regulatory authority sets the ROE too low, the stockholders will not have the opportunity to earn a fair return; if the regulatory authority sets the ROE too high, the customers will pay too much, and the resulting rates will be unfair, unjust, and unreasonable.

Q. HOW DOES THE MANNER IN WHICH UTILITIES OBTAIN CAPITAL FUNDING RELATE TO THE COMMISSION'S DETERMINATION OF THE APPROPRIATE COST OF CAPITAL FOR A SPECIFIC UTILITY?

A. Utilities obtain capital funding through a combination of borrowing (debt financing) and issuing stock (equity financing). Except for instances where a company's borrowing is determined to be imprudent, the determination of ratepayer reimbursement for debt financing (*i.e.* the debt cost) is generally uncontroversial.

In contrast, the determination of the allowed ROE is where disputes often arise. The allowed ROE is the amount that is determined to be appropriate for the utility's common stockholders to earn.

[42] Snl.com

Q. HOW DO REGULATORY AUTHORITIES DETERMINE A FAIR RATE OF RETURN ON EQUITY?

A. Regulatory commissions and boards, as well as financial industry analysts, institutional investors, and individual investors, use different analytical models and methodologies to estimate/calculate reasonable rates of return on equity. Among the measures used are Discounted Cash Flow ("DCF" analysis), the Comparable Earnings Analysis, the Capital Asset Pricing Model ("CAPM" method), and a variation of the CAPM called the Risk Premium method. As I will show later in this testimony, the CAPM and Risk Premium models, at least as applied by Mr. Hevert in this case, produce unrealistic results relative to prevailing capital markets. I believe the most useful methodology, when applied appropriately, is the DCF Analysis. However, to check the reasonableness of my DCF analysis and to gauge the proper ROE to recommend within the DCF range, I will also present both a Comparable Earnings analysis and a CAPM analysis.

Q. WHAT IS THE "COMPARABLE EARNINGS" TEST AND HOW DOES THAT FACTOR IN TO DETERMINING THE APPROPRIATE RETURN ON EQUITY FOR DUKE?

A. The "comparable earnings" standard, "i.e." that earnings must be "commensurate with the returns on investments in other enterprises having corresponding risks," is derived from the Supreme Court's ruling in the *Hope Natural Gas* case to which I earlier referred. In my opinion, enterprises of "corresponding" or comparable risk are companies that are engaged in the same activities as DEC and are also regulated like DEC.

Q. HAVE YOU PREVIOUSLY PRESENTED THE CAPM IN COST OF EQUITY TESTIMONIES?

A. Yes, but I have not given it much weight. I have long maintained the application of the CAPM can lead one to erroneous results when applied in an inaccurate manner, such as when "forecasted" risk premiums or "forecasted" interest rates are employed. For this reason, I have historically not used the CAPM in cost of equity analyses. However, I do recognize the Federal Energy Regulatory Commission ("FERC") and at least one state commission, the Maryland Public Service Commission, have recently expressed an interest in reviewing additional models in the cost of equity analysis. As a result of the FERC and Maryland decisions, I am adding the CAPM in my analysis to supplement my DCF analysis as well as my Comparable Earnings analysis.

Q. PLEASE DESCRIBE HOW YOU SELECTED A PROXY GROUP FOR ESTIMATING DUKE'S RETURN ON EQUITY.

A. For the purposes of this proceeding, with the exception of two companies, I will adopt the comparable group of Mr. Hevert. The two companies I excluded were SCANA Corp. and Dominion as these companies are involved in ongoing merger discussions.

Based on past experience, I have learned the primary difference between myself and Mr. Hevert is in the details <u>and the consistency of</u> how we apply our cost of equity models and not the individual composition of our comparable group. For that reason, with the exception of Dominion, and SCANA, I will adopt Mr. Hevert's comparable group so the Commission can focus on the application of the various methods used to develop our recommended ROEs.

(c) <u>Discounted Cash Flow ("DCF") Analysis</u>

Q. CAN YOU PLEASE EXPLAIN THE DISCOUNTED CASH FLOW METHOD?

A. Yes. The DCF method is a widely used method for estimating an investor's required return on a firm's common equity. In my 33 years of experience with the Public Staff of the North Carolina Utilities Commission and as a consultant, I have seen the DCF method used much more often than any other method for estimating the appropriate return on common equity. Consumer advocate witnesses, utility witnesses, and other intervenor witnesses have used the DCF method, either by itself or in conjunction with other methods such as the Comparable Earnings Method or the Capital Asset Pricing Model, in their analyses.

The DCF method is based on the concept that the price the investor is willing to pay for a stock is the discounted present value or present worth of what the investor expects to receive from purchasing that stock. This return to the investor is in the form of future dividends and price appreciation. However, price appreciation can be ignored because appreciation in price is only realized when the investor sells the stock. Therefore, the only income that an investor will receive from the company in which it invests is the dividend stream. Mathematically, the relationship is:

Let D = dividends per share in the initial future period
g = expected growth rate in dividends
k = cost of equity capital
P = price of asset (or present value of a future stream of dividends)

$$\text{then } P = \frac{D}{(1+k)} + \frac{D(1+g)}{(1+k)^2} + \frac{D(1+g)}{(1+k)^3} + \ldots\ldots + \frac{D(1+g)}{(1+k)^t}$$

This equation represents the amount (P) an investor will be willing to pay for a share of common equity with a given dividend stream over (t) periods.

Reducing the formula to an infinite geometric series, we have:

$$P = \frac{D}{k-g}$$

Solving for k yields:

$$k = \frac{D}{P} + g$$

Q. MR. O'DONNELL, DO INVESTORS IN UTILITY COMMON STOCKS REALLY USE THE DCF MODEL IN MAKING INVESTMENT DECISIONS?

A. Yes. Utility investors tend to be individuals or institutions interested in current income. Given the current historically low environment for fixed income securities, many investors are interested in utility stocks as they provide income sources during a time of low interest rates. In today's investment environment, the average stock investor will calculate the amount of funds he/she will receive relative to the initial investment, which is defined as the current dividend yield and the amount of funds that the investor can expect in the future from the growth in the dividend. The combination of the current dividend yield and the future growth in dividends is central to the basic tenet of the DCF model.

Q. HAVE YOU USED THE DCF MODEL IN ANALYZING COMMON STOCKS FOR INVESTMENT PURPOSES?

A. Yes. I have used and continue to use the DCF method extensively in analyzing common stocks for potential personal purchases.

Although the DCF formula stated above may appear complicated, the DCF method is intuitively a very simple model to understand. To determine the total rate of return one expects from investing in a particular equity security, the investor adds the dividend yield that he or she expects to receive in the future to the expected growth in dividends over time. If the regulatory authority sets the rate at a fair level, the utility will be able to attract capital at a reasonable cost, without forcing the utility's customers to pay more than necessary to attract needed capital.

Unlike models such as the CAPM, which is more theoretical and academic in nature, the DCF is grounded in solid practicality that is used by money managers and individual investors throughout the world on a daily basis.

Q. HAVE YOU PREPARED ANY ANALYSES USING THE DCF METHOD TO EVALUATE A FAIR RATE OF RETURN IN THIS CASE?

A. Yes, I have. I prepared a DCF analysis for Duke Energy, which is the parent holding company of DEC, as well as for a group of the same comparable companies employed by Mr. Hevert.

Q. PLEASE EXPLAIN WHY YOU DID NOT COMPLETE A DCF ANALYSIS DIRECTLY ON DUKE ENERGYCAROLINAS?

A. I was not able to perform a DCF analysis directly on DEC because the utility is a subsidiary of Duke Energy Corp. and DEC's stock is not publicly traded. However, because Duke Energy is publicly traded, I was able to perform a rate of return analysis on the parent company.

Q. WHAT DIVIDEND YIELD DO YOU THINK IS APPROPRIATE FOR USE IN THE DCF MODEL?

A. I have calculated the appropriate dividend yield by averaging the dividend yield expected over the next 12 months for each comparable company, as reported by the <u>Value Line Investment Survey</u>. The period covered is from Oct. 6, 2017 through December 29, 2017. To study the short-term as well as long-term movements in dividend yields, I examined the 13-week, 4-week, and 1-week dividend yields for the comparable groups. My results appear in Exhibit KWO-1 and show a dividend yield, during the three time periods examined, of 3.1% to 3.2% for the comparable group and 4.1% to 4.3% for Duke Energy.

Q PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELD RANGES DISCUSSED ABOVE.

A. I developed the dividend yield range for the comparable group by averaging each Company's dividend yield over the above-stated 13-week and 4-week periods, as well as examining the most recent dividend yield reported by Value Line for each company.

Q. HOW DID YOU DERIVE THE EXPECTED GROWTH RATE?

A. I used several methods to determine the growth in dividends that investors expect.

"Plowback Ratio Method"

The first method I used was an analysis commonly referred to as the "plowback ratio" method. If a company is earning a rate of return (r) on its common equity, and it retains a percentage of these earnings (b), then each year the earnings per share (EPS) are expected to increase by the product (br) of its earnings per share in the previous year. Therefore, br is a good measure of growth in dividends per share. For example, if a company earns 10% on its equity and retains 50% (the other 50% being paid out in dividends), then the expected growth rate in earnings and dividends is 5% (50% of 10%). To calculate a plowback for the comparable group, I used the following formula:

$$g = \frac{br(2015) + br(2016) + br(2017E) + br(2020E\text{-}2022E\ Avg)}{4}$$

The plowback estimates for all companies in both comparable groups can be obtained from The Value Line Investment Survey under the title "percent retained to common equity." Exhibit KWO-2 lists the plowback ratios for each company in the comparable group. The plowback method is a very useful tool for comparing the comparable group's growth rates on a recent historical basis as well as a short-term forecasted basis.

A key component in the DCF Method is the expected growth in dividends. In analyzing the proper dividend growth rate to use in the DCF Method, the analyst must consider how dividends are created. Because dividends cannot be paid out without the company first earning the funds to be paid out, earnings growth is a key element in analyzing the expected growth in dividends. Similarly, what remains in a company after it pays its dividend is reinvested, or "plowed back", into the company in order to generate future growth. As a result, book value growth is another element that, in my opinion, must be considered in analyzing a company's expected dividend growth.

Historical Compound Rates of Change

To analyze the expected growth in dividends, I believe the analyst should first examine the historical record of past earnings, dividends, and book value. Hence, the second method I used to estimate the expected growth rate was to analyze the historical 10-year and 5-year compound annual rates of change for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BPS") as reported by Value Line.

Value Line is the most recognized investment publication in the industry and, as such, is used by professional money managers, financial analysts, and individual investors worldwide. A prudent investor examines all aspects of a Company's performance when making a capital investment decision. It is only practical to examine historical growth rates for the company for which the analysis is being performed. The historical growth rates for the comparable group can be seen in Exhibit KWO-1. Some analysts, such as Mr. Hevert, do not present historical growth rates in their DCF analyses. I believe that failing to completely provide and include available and relevant data deprives the respective regulatory body of the full extent of information on which investors base their expectations.

Forecast Compound Rates of Change

The <u>third method</u> I used was the <u>Value Line</u> forecasted compound annual rates of change for earnings per share, dividends per share, and book value per share.

Forecast Rate of Change in EPS

The fourth method I used was the forecasted rate of change for earnings per share that analysts supplied to Charles Schwab & Co. This forecasted rate of change is not a forecast supplied by Thomson Reuters and Charles Schwab & Co. but is, instead, a compilation of forecasts by industry analysts.

The details of the DCF results can be seen in Exhibit KWO-1. In this exhibit, I present all the growth rates I examined in my analysis and, later in this testimony, discuss exactly how I determined the proper growth rate range to use in calculating the investor return requirement for Duke Energy in this case.

Q. WHAT IS THE INVESTOR RETURN REQUIREMENT FROM THE DCF ANALYSIS?

As can be seen on Exhibit KWO-1, the dividend yield for my comparable group for the three time frames studied is 3.1% to 3.2% for the comparable and 4.1% to 4.3% for Duke Energy.

In terms of the proper dividend growth rate to employ in this analysis, I believe that it is appropriate to examine the recent history of earnings and dividend growth to assess and provide the best estimate of the dividend growth that investors expect in the future. A quick examination of the 10-year and 5-year historical growth rates shows a relatively tight range of historical growth rates for the comparable group. Duke, on the other hand, has had a much wider range of historical growth rates over the past ten years.

A review of all the growth rates can be seen in the table below.

Table 10: Comparable Group and Duke Energy Growth Rates

	Historical		Plowback	Forecasted	
	Low	High		Low	High
Comparable Group	4.0%	7.0%	3.7%	4.2%	5.6%
Duke Energy	-0.5%	3.5%	1.4%	1.5%	4.5%

Q. WHY ARE DUKE'S GROWTH RATES SO MUCH LOWER THAN THOSE OF THE COMPARABLE GROUP?

A. Duke's corporate strategy of-late has been to return to its roots of a regulated utility and to remove itself from non-utility investments. The June 15, 2017 RRA report on Duke noted the following:

> With respect to a comparison to its peers, Duke Energy, among the largest utility holding companies in the U.S. with respect to many financial and operating metrics, is at the bottom of the group with respect to earned ROE and cash flow coverage of dividends for the twelve months ended March 31, 2017. Duke's earned ROE is significantly higher when excluding goodwill.[43] (underline added)

On Oct. 26, 2015, Barrons published an article where Citigroup analyst Praful Mehta stated that Duke Energy was overpaying for Piedmont Natural Gas in "almost any reasonable scenario."[44] The article goes on to state:

43 Regulatory Research Associates, June 15, 2017

44 Barrons, Oct. 26, 2015,

> Red flag on growth at underlying business and management's direction: A majority of utility deals, unfortunately, have been driven by the need to solve problems and this deal seems to be consistent with that theme. Management knew they were paying a big premium that the market would worry about but they still went ahead with the deal. To us, this raises two questions: Firstly, is there a meaningful problem in the growth profile of the underlying business (LatAm)? Secondly, would management rather destroy value to hold on to a growth target that may not be achievable rather than realign growth targets?[45]

Mr. Mehta, obviously, knew what he was saying because Duke Energy has, subsequently, sold its Latin America unregulated business.

The current reality for Duke is that its stock is priced below that of other utilities, at least based on dividend yields. The fact that consumers are not willing to pay as much for Duke as they are for other utilities is due, in large part, to the significantly lower growth rates of Duke relative to its peers. Duke management chose to retrench the Company from its unregulated operations (Latin American asset sale) and double-down on regulated utilities by overpaying for Piedmont. Management's plan to grow earnings at Duke is to invest billions of dollars into its regulated operations. The problem with this strategy is it will force Duke's rates to skyrocket, thereby harming the North Carolina economy and consumer budgets.

Even more harmful is the fact Duke management knows customers do not want excessive rate increases to pay for Project GRIM, but they are moving forward with legislative and regulatory efforts to push this plan onto consumers anyhow. As shown previously, the economic study on which Duke is basing Project GRIM is badly flawed, there again exposing Duke management's primary goal to drive earnings with considerably less regard given to the financial impact on consumers.

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45 Id at

Q. WHAT DO YOU BELIEVE IS THE PROPER GROWTH RATE RANGE TO USE IN THE DCF ANALYSIS?

A. I believe that the proper growth rate range for the comparable group is in the range of 4.75% to 5.75%. The bottom end of the range is: above the historical low growth rate; above the plowback average; and above the low forecasted growth rate. The high end of the range is almost identical to the high end of the forecasted growth rates and is below the historical high growth rate. However, it should be noted that the comparable group has several very high historical growth rates. If the Otter Tail historical growth rate of 25% was taken out of the group, the average growth rate falls from 7.0% to 5.9%.

It is important to note the forecasted growth rates are actually well above the forecasted gross domestic product (GDP) growth rates that are expected to remain in the area of 2% to 3% for the foreseeable long-term future.

The proper long-term growth rate range for Duke Energy is in the range of 3.5% to 4.5%. With this range, I have, obviously, discounted the poor historical results of Duke and, instead, focused on the more optimistic forecasted results.

Combining the above-stated dividend yields and growth rates for both comparable groups and Duke's produces the following results:

Table 11: DCF Results

	Dividend Yield	Dividend Growth Rate Range		DCF Range	
		Low	High	Low	High
Comparable Group	3.20%	4.75%	5.75%	7.95%	8.95%
Duke	4.30%	3.50%	4.50%	7.80%	8.80%

Based on the results as stated in Table 11 above, the DCF results for Duke Energy in this case are in the range of 8.0% to 9.0% as this range is approximately in the middle of the DCF results for both comparable groups as well as Duke Energy.

(d) Comparable Earnings Analysis

Q. MR. O'DONNELL, WOULD YOU PLEASE EXPLAIN WHY YOU PERFORMED A COMPARABLE EARNINGS ANALYSIS IN ADDITION TO YOUR DCF ANALYSIS?

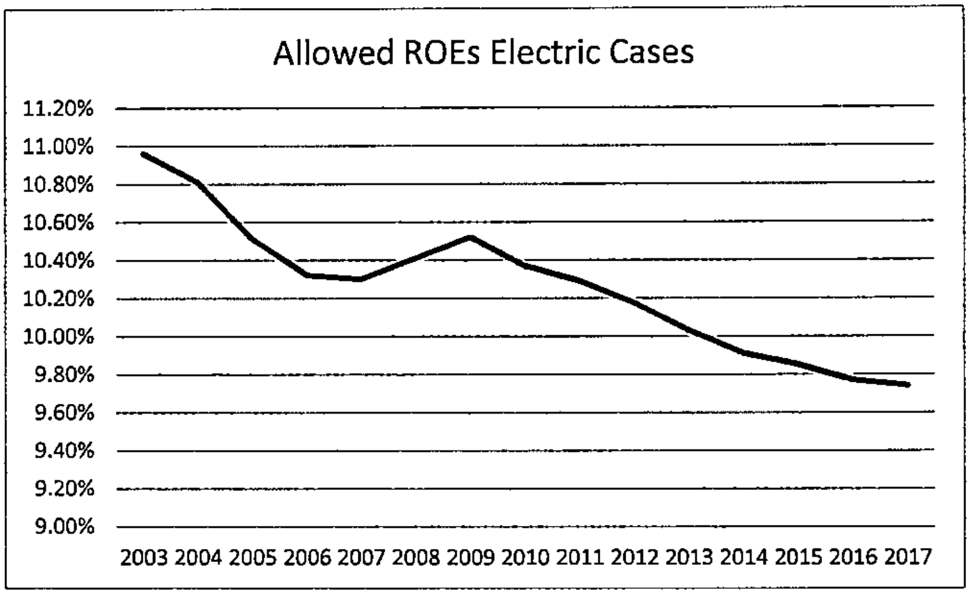
A. Yes. The comparable earnings method provides investors with actual historical earned returns on common equity. Investors use this information as a guide to assess an investment's current required rate of return. I used the comparable earnings method in my analysis in this case to assess the reasonableness of my DCF results and to provide an independent methodological estimate of the return that investors would consider reasonable for Duke.

Q. WOULD YOU PLEASE EXPLAIN HOW YOU PERFORMED THE COMPARABLE EARNINGS ANALYSIS?

A. Exhibit KWO-3 presents a list of the earned returns on equity of the comparable group and Duke Energy over the period of 2015 through 2022. I picked this range to provide the Commission with a balance of historical returns and forecasted returns. As can be seen in this exhibit, the earned returns on equity for my comparable group have been, and are expected to be in the future, approximately 9.25% to 10.25%.

The earned returns of Duke Energy are also found in Exhibit KWO-3 and are in the range of 7.5% to 8.5%. Clearly, for the past two years and the foreseeable future, the earned returns for Duke Energy are not as high as the average of the comparable groups.

Chart 5: Allowed Electric ROEs 2003-2017



Source for raw data: SNL.com

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE COMPARABLE EARNINGS ANALYSIS?

A. Based on the above-stated findings, I believe the proper rate of return using a comparable earnings analysis is in the range of 8.75% to 9.75%. The 8.75% lower end of the range reflects the lower earned returns of Duke Energy. The high end of the range reflects the average earned returns of the comparable group. Of the allowed ROEs in 2017 by state regulators, approximately 9.69%, falls in the upper end of this 9.0% to 10.0% range.

(e) <u>Capital Asset Pricing Model (CAPM)</u>

Q. MR. O'DONNELL, PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL.

A. The CAPM is a risk premium model that determines a firm's ROE relative to the overall market return on equity. The formula for the CAPM is as follows:

ROE = Rf + Beta [E(RM) – Rf]

where ROE is the return on equity;
Rf is the risk-free rate;
Beta is the risk of the studied company relative to the overall market; and
E(RM) is the expected return on the market.

To be specific, the CAPM is a measure of firm-specific risk, known as unsystematic risk and measured by beta, as well as overall market risk, otherwise known as systematic risk and measured by the expected return on the market.

The CAPM calculates ROE based on a company's risk and can be restated as follows:

ROE = Rf + (Beta * Risk Premium)

where Risk Premium represents the adjusted company-specific risk of the company.

Q. HOW IS THE RISK-FREE RATE MEASURED?

A. The risk-free rates are designated as the yield on United States government bonds, but the term of those bonds is often debated by investment professionals. In my analysis for this case, I have developed risk premiums relative to the 30-year US Treasury bonds, which are currently yielding approximately 2.9%.

Q. IS THE CURRENT LEVEL OF INTEREST RATES EXPECTED TO CHANGE MATERIALLY IN THE FORESEEABLE FUTURE?

A. No. Economic forecasters as well as the Federal Reserve all believe that the current interest rate environment is expected to remain relatively stable for many years to come. In fact, in June 16, 2016, Bloomberg published an article entitled "Yellen Says Forces Holding Down Rates May Be Long Lasting" that stated:

> 'New Normal'
>
> In a press conference after the Fed held policy steady, Yellen spoke of a sense that rates may be depressed by "factors that are not going to be rapidly disappearing, but will be part of the new normal."
>
> Summers, who was in the running to get the Fed job before losing out to Yellen in 2013, has been contending for several years that the U.S. and other industrial countries are mired in "secular stagnation" of scant economic growth.
>
> A key component of his argument: An excess supply of savings and a paucity of demand are depressing equilibrium interest rates in the advanced world, making it difficult for central banks to ease credit enough to lift growth and inflation.
>
> The equilibrium, or neutral rate, is the one that balances the supply of and demand for savings in an economy. If a central bank wants to spur growth it has to cut rates below that level. [46]

Q. HOW IS BETA MEASURED IN THE CAPM?

A. Beta is a statistical calculation of a company's stock price movement relative to the overall stock movement. A company whose stock price is less volatile than the overall market will have a beta less than 1.0. A company whose stock price is more volatile than the overall market will have a beta more than 1.0. Since utilities are generally conservative equity investments, utility betas are almost always less than 1.0.

Q. WHAT IS THE CURRENT MARKET RISK PREMIUM APPROPRIATE FOR USE IN THE CAPM?

46 "Yellen Says Forces Holding Down Rates May Be Long Lasting," Barrons, June 16, 2016

A. The development of the current market risk premium is, undoubtedly, the most controversial aspect of the CAPM calculations. Utility witnesses, such as Mr. Hevert, wish to ignore historical risk premiums as combining those returns with returns from the current low interest rate environment produces returns too low for their utility clients. However, ignoring historical returns neglects an important part of investor reactions. To gauge the historical risk premium, I turned to the Ibbotson database published by Morningstar. The long-term geometric and arithmetic returns for both equities and fixed income securities and the resulting risk premiums are as follows:

Table 12: Equity Risk Premium Calculations

Asset Class	Geometric Mean	Arithmetic Mean
Large Company Stocks	10.10%	12.10%
Long-Term Govt. Bonds	5.50%	5.90%
Resulting Risk Premium	4.60%	6.20%

Source: Ibbotson® SBBI®, 2014 Classic Yearbook: Market Results for Stocks, Bonds, Bills, and Inflation, 1926–2013 (Chicago: Morningstar, 2014).

Q. **WHAT MARKET RETURNS ARE WELL-KNOWN PROFESSIONAL INVESTORS EXPECTING FOR THE FORESEEABLE FUTURE?**

A. On January 14, 2016, Morningstar.com published an article entitled "What Market Experts are Saying About Future Returns." By future returns, these market experts are discussing total market returns, and not just the equity risk premium. Below are some of the market return forecasts from this article:

John Bogle, Founder of Vanguard Group

6% nominal (non-inflation adjusted) equity returns during the next decade [47]

<u>Josh Peters, Morningstar Director of Equity-Income Strategy and Morningstar Dividend Investor Editor</u>

6-7% (nominal 4-5%) returns for the S&P 500 over the next few decades [48]

<u>Matt Coffina, Morningstar Equity Strategist and Morningstar Stock Investor Editor</u>

6% to 8% over the long-run [49]

<u>Morningstar Investment Management</u>

4.5% 10-year nominal returns for US stocks [50]

<u>Charles Schwab</u>

6.3% nominal returns for US large caps (the S&P 500) during the next 10 years [51]

<u>Vanguard</u>

Nominal equity market returns of 6% to 8% during the next decade [52]

The above-stated equity returns are consistently in the 6% to 8% range. When the current yield of approximately 2.9%, which is the one-year average of 30-year US Treasuries, is deducted from this expected return, the resulting equity risk premium is between 3.1% and 5.1%.

Q. WHAT IS YOUR CONCLUSION AS TO THE ESTIMATED EQUITY

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47 What Market Experts are Saying About Future Returns", Morningstar, January 14, 2016,

48 Id

49 id

50 id

51 id

52 id

RISK PREMIUM FOR USE IN THE CAPM?

A. Using historical data as well as ex ante (forecasts) data, the evidence suggests the equity risk premium is clearly between the range of 4% to 6%.

Q. HOW DID YOU DETERMINE THE BETA YOU USED IN THE CAPM?

A. I used the Value Line derived beta that I found in the most recent Value Line editions for Duke and each company in the comparable group.

Q. WHAT WERE YOUR CAPM RESULTS?

A. The actual calculations for the CAPM can be seen in Exhibit KWO-4 and show a range of 5.06% to 7.52%.

7. Return on Equity Recommendation

Q. MR. O'DONNELL, PLEASE SUMMARIZE THE RESULTS OF YOUR ROE ANALYSIS IN THIS CASE.

A. Table 13 below lists the results of my DCF analysis, the Comparable Earnings analysis, and the CAPM:

Table 13: ROE Method Results

Method	ROE Results	
	Low	High
DCF	8.00%	9.00%
Comparable Group	9.00%	10.00%
CAPM	5.06%	7.52%

Q. IS THERE A REASON FOR THE RELATIVELY HIGH RESULTS FOR THE COMPARABLE EARNINGS MODEL?

A. Yes. The stock market continues to be in a bullish position whereby stockholders are paying strong premiums for equities that produce solid dividends because of low interest rates. As a result, investors are essentially saying that they are willing to pay these premiums today to lock in future strong dividend growth in the future and, in doing so, will accept lower returns through the DCF model.

Q. WHAT IS YOUR RECOMMENDATION FOR THE RETURN ON EQUITY AND OVERALL RATE OF RETURN THE COMMISSION SHOULD USE IN THIS PROCEEDING?

A. My specific recommendation in this case is for the Commission to grant DEC a return on equity of 9.0%. This 9.0% ROE is at the top end of my DCF results; is at the low-end of the range of the results for the comparable earnings analysis; and is well above the CAPM results.

Q. HOW DOES YOUR RECOMMENDED ROE OF 9.0% COMPARE TO WHAT ANALYSTS ARE EXPECTING FOR FUTURE MARKET RETURNS?

A. My recommended ROE of 9.0% is well-above what market experts are forecasting for future market returns. On Nov. 4, 2012, an insightful article entitled "Kiss 10% Market Returns Goodbye" was published by Market Watch of the Wall Street Journal. Dr. Roger Ibbotson, Emeritus Professor of Finance at Yale University stated that, over the next 25 years, returns will not exceed 8%. The Wall Street Journal explained:

> "Starting in 1926, the return on the large cap market has been 9.8%, but this was during a period when inflation rates are higher than they are today, and risk-less rates were higher than they are today," said Ibbotson, a Yale professor who also currently serves as chairman and chief investment officer at Zebra Capital Management. "You have to knock it all down a couple of percent, because we really are in a risk-less rate environment where the rates are close to zero."

> For the next quarter century or more, Ibbotson said he would "not predict more than an 8% return on the market but that's not bad. That's a great return." [53]

Q. HOW WILL DIMINISHED EXPECTED STOCK MARKET RETURNS AFFECT RETURNS AS SET BY STATE UTILITY REGULATORS ACROSS THE COUNTRY?

A. It is important to note that stock market returns and rate base returns as set by state regulators are two different items. Stocks may go up and down, without much influence from the actions and official determinations of state regulators. However, there is no doubt that state regulators have noticed the tremendous increase in the stock market and correspondingly lower debt costs over the past six years and have lowered the allowed rate of return granted to utilities over this time period.

If market returns are in the single-digits for years to come and the U.S. economy continues its present slow expansion in the years ahead, allowed returns on equity for regulated utilities should either decrease or stay roughly at current levels for the foreseeable future.

Q. DO YOU EXPECT THE LOWER STOCK MARKET RETURNS TO NEGATIVELY IMPACT CREDIT PROFILES OF UTILITIES?

A. No. The markets have noticed the lower capital market returns and adjusted accordingly. In 2015 Moody's published an article that discussed the current low ROEs and the associated impact on credit profiles. The article stated the following:

> The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity

53 "Kiss 10% Market Returns Goodbye", Wall Street Journal, Nov. 4, 2012

> (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a low business risk profile for utilities, prompting regulators to scrutinize their profitability, which is defined as the ratio of net income to book equity. We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures.[54]

8. Capital Structure

Q. WHAT IS A CAPITAL STRUCTURE AND HOW WILL IT IMPACT THE REVENUES THAT DUKE OR ANY OTHER UTILITY IS SEEKING IN A RATE CASE?

A. The term "capital structure" refers to the relative percentage of debt, equity, and other financial components that are used to finance a company's investments.

For simplicity, there are three financing methods. The first method is to finance an investment with common equity, which essentially represents ownership in a company and its investments. Returns on common equity, which in part take the form of dividends to stockholders, are not tax deductible which, on a pre-tax basis alone, makes this form of financing about 40% more expensive than debt financing. The second form of corporate financing is preferred stock, which is normally used to a much smaller degree in capital structures. Dividend payments associated with preferred stock are not tax deductible. Corporate debt is the third major form of financing used in the corporate world. There are two basic types of corporate debt: long-term and short-term. Long-term debt is generally understood to be debt that matures in a period of more than one year. Short-term debt is debt that matures in a year or less. Both long-term debt and short-term

54 "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles", Moodys, March 10, 2015, 1

debt represent liabilities on the company's books that must be repaid prior to any common stockholders or preferred stockholders receiving a return on their investment.

Q. HOW IS A UTILITY'S TOTAL RETURN CALCULATED?

A. A utility's total return is developed by multiplying the component percentages of its capital structure represented by the percentage ratios of the various forms of capital financing relative to the total financing on the company's books by the cost rates associated with each form of capital and then totaling the results over all of the capital components. When these percentage ratios are applied to various cost rates, a total after-tax rate of return is developed. Because the utility must pay dividends associated with common equity and preferred stock with after-tax funds, the post-tax returns are then converted to pre-tax returns by grossing up the common equity and preferred stock dividends for taxes. The final pre-tax return is then multiplied by the Company's rate base in order to develop the amount of money that customers must pay to the utility for return on investment and income tax payments associated with that investment.

Q. HOW DOES CAPITAL STRUCTURE IMPACT THIS CALCULATION?

A. Costs to consumers are greater when the utility finances a higher proportion of its rate base investment with common equity and preferred stock versus long-term debt. However, long-term debt, which is first in line for repayment, imposes a contractual obligation to make fixed payments on a pre-established schedule, as opposed to common equity where no similar obligations exist.

Q. WHY SHOULD THE COMMISSION BE CONCERNED ABOUT HOW DUKE FINANCES ITS RATE BASE INVESTMENT?

A. There are two reasons that the Commission should be concerned about how Duke finances its rate base investment. First, Duke's cost of common equity is higher than the cost of long-term debt, meaning that an equity percentage above an optimal level will translate into higher costs to Duke's customers without any corresponding improvement in quality of service. Long-term debt is a financial promise made by the company and is carried as a liability on the company's books. Common stock is ownership in the company. Due to the nature of this investment, common stockholders require higher rates of return to compensate them for the extra risk involved in owning part of the company versus having a more senior claim against the company's assets.

The second reason the Commission should be concerned about Duke's capital structure is due to the tax treatment of debt versus common equity. Public corporations, such as Duke, can expense interest payments associated with debt financing. Corporations are not, however, allowed to deduct common stock dividend payments for tax purposes. All dividend payments must be made with after-tax funds, which are more expensive than pre-tax funds. Because the regulatory process allows utilities to recover reasonable and prudent expenses, including taxes, rates must be set so that the utility pays all its taxes and has enough left over to pay its common stock dividend. If a utility is allowed to use a capital structure for ratemaking purposes that is top-heavy in common stock, customers will be forced to pay the associated income tax burden, resulting in unjust, unreasonable, and unnecessarily high rates. Setting rates through the use of capital structure that is top-heavy in common equity violates the fundamental principles of utility regulation, that rates must be just and reasonable, and only high enough to support the utility's provision of safe, adequate, and reliable service at a fair price.

Q. WHAT CAPITAL STRUCTURE IS DUKE SEEKING IN THIS CASE?

A. DEC is seeking approval of the following capital structure and cost rates.

Table 14: DEC Requested Capital Structure and Debt Cost Rates

Component	Capital Structure Ratio (%)	Cost Rate (%)
Long-Term Debt	47.00%	4.74%
Common Equity	53.00%	----
Total Capitalization	100.00%	

Q. MR. O'DONNELL, WHAT IS THE AVERAGE COMMON EQUITY RATIO OF THE COMPANIES IN YOUR COMPARABLE GROUP?

A. Table 15 below shows the average common equity ratio of each company in the comparable group.

Table 15: Comparable Group Equity Ratios

Company	**2016 Equity Ratio**
ALLETE Inc	58.0%
Alliant Energy Corp	47.2%
Ameren Corp	51.3%
American Electric Power Co Inc	50.0%
Avista	48.8%
Black Hills Corp	33.5%
CMS Energy Corp	32.6%
DTE Energy Co	44.4%
IDACORP Inc	55.2%
Northwestern Corp	48.0%
OGE Energy Corp	58.9%
Otter Tail Corp	57.0%
Pinnacle West Capital Corp	54.4%
PNM Resources Inc	44.0%
Portland General Electric Co	51.6%

Southern Company	35.7%
WEC Energy Group Inc	49.3%
Xcel Energy Inc	43.7%
Average	48.0%
Duke Energy Corp	47.4%

As can be seen in the table above, the average common equity ratio in the comparable group is 48.0%.

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO GRANTED TO ELECTRIC UTILITIES BY REGULATORS ACROSS THE UNITED STATES IN 2016 THROUGH TO-DATE IN 2017?

A. The average common equity ratio granted by regulators in 2017 was 49.1%. [55]

Q. WHAT IS THE EQUITY RATIO OF DUKE ENERGY?

A. The common equity ratio of Duke Energy Corp. as of December 31, 2016 was 47.4%.

Q. DO YOU BELIEVE DEC'S EQUITY RATIO IS COMPARABLE TO THE EQUITY RATIOS OF SIMILAR COMPANIES?

A. No. Table 16 below shows that DEC's requested common equity ratio in relation to my comparable group, the comparable group, Duke Energy, and the common equity ratios granted by state regulators in 2017.

Table 16: Common Equity Comparison

55 Data from snl.com

DEC Requested Equity Ratio	53.0% -
Comparable Group	48.0%
Duke Energy	47.4%
Average Eq. Ratio Granted by Regulators	49.1%

The common equity ratio requested by DEC in this case is excessive as compared to the comparable group, Duke Energy (holding company), and the average common equity ratio as granted by state regulators from across the United States.

I understand rates were set in Duke's last rate case to support the Company's requested 53% equity ratio in that case. I further understand the Public Staff and Duke settled on a 52% common equity ratio in the 2017 Duke Energy Progress rate case. However, both of those cases involved a stipulation. To-date, this case has not been settled and Duke has not provided any evidence to support its requested equity ratio of 53% in this case. As can be seen above, DEC's request in this case is grossly excessive as compared to the equity ratio of other utilities, including Duke Energy Corp.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND TO THE COMMISSION IN THIS CASE?

A. I recommend a capital structure that consists of 50% common equity and 50% long-term debt. My recommendation of a 50% equity ratio is higher than the average equity ratio of the comparable group and is also higher than the equity ratio of Duke Energy Corp.

I agree with the Company's proposed embedded cost of long-term debt rate of 4.74%

Q. WHAT IS YOUR OVERALL RECOMMENDED RATE OF RETURN?

A. My recommended overall rate of return is 6.59% and can be seen in Table 17 below.

Table 17: CUCA Recommended Overall Rate of Return

Component	Capital Structure Ratio (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	50.00%	4.74%	2.37%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	100.00%		6.87%

9. Critique of Testimony of Company Witness Hevert

Q. MR. O'DONNELL, HAS MR. HEVERT BEEN CONSISTENT IN HIS APPLICATION OF THE VARIOUS COST OF CAPITAL METHODS OVER THE YEARS HE HAS BEEN PRESENTING TESTIMONY ON BEHALF OF HIS UTILITY CLIENTS?

A. No. Mr. Hevert has changed the application of his cost of capital models over the years so that the results produce higher cost of capital results for his utility clients than would be produced by a consistent application of his models.

Q. PLEASE EXPLAIN HOW MR. HEVERT APPLIES THE CAPM IN THE CURRENT CASE.

A. In the current case, Mr. Hevert uses a forward-looking DCF model to determine an expected market return. He then subtracts out the yield on 30-year Treasury bonds to determine a market risk premium for use in the CAPM.

Q. IS MR. HEVERT'S APPLICATION OF THE CAPM IN THIS CASE CONSISTENT WITH THE WAY HE HAS APPLIED THE CAPM IN PAST CASES?

A. No, it is not.

Q. HOW IS MR. HEVERT'S CURRENT APPLICATION OF THE CAPM DIFFERENT FROM HIS PAST APPLICATIONS?

A. Mr. Hevert has changed his application of the CAPM in the two very distinct ways:

1. he has changed the actual market risk premiums used in the CAPM; and
2. he has changed his reliance on historical data versus forecasted data he employs in the CAPM.

In the situations noted above, the result is that Mr. Hevert's calculations lead to higher return on equity numbers for his clients.

Q. PLEASE EXPLAIN MR. HEVERT'S CHANGES IN THE MARKET RISK PREMIUM IN THE CAPM.

A. Mr. Hevert has been presenting testimony on behalf of utilities for a number of years and has built up a history of cases in which he has used the CAPM. A review of prior cases shows Mr. Hevert has changed his risk premiums frequently throughout his tenure as an expert witness before various state regulatory bodies. As an example, Table 18 below shows Mr. Hevert's calculated risk premiums in five cases since 2008.

Table 18: Historical Hevert Market Risk Premiums

Year	Implied Mkt. Premium

2008	7.10% [56]
2009	7.19% - 8.10% [57]
2014	8.71% - 10.31% [58]
2015	10.07% - 10.82% [59]
2016	9.99% - 11.81% [60]
2017	9.37% - 11.27% [61]

As demonstrated in this table, in 2008, Mr. Hevert used a market risk premium of 7.10% in his CAPM calculations. In 2017, Mr. Hevert employed a risk premium as high as 11.27% in his CAPM. In his 2008 South Dakota testimony, Mr. Hevert states that the 30-day average yield on a 30-year U.S. Treasury bond was 4.22% (South Dakota Public Utilities Commission, Docket No. EL08-030, Schedule 4, p. 1). In this proceeding, he cites the yield on the 30-year U.S. Treasury bond to be 3.06%. *See* Exhibit RBH-5, p. 1.

Even though the risk-free rate has fallen 116 basis points since 2008, Mr. Hevert's risk premiums have increased 417 basis points during this same time period. With results such as cited above, Mr. Hevert's unique application of the CAPM will never result in a lower ROE for his client. With results such as stated above, it is little wonder why DEC has an existing and ongoing relationship with Mr. Hevert as his testimony, irrespective of the current interest rate environment, can produce high ROE values for Duke and Mr. Hevert's

[56] Otter Tail Power Company, South Dakota Public Utilities Commission, Docket No. EL08-030, Schedule 4, 1

[57] South Carolina Electric & Gas, South Carolina Public Service Commission, Docket No. 2009-489-E, Exhibit RBH-2, 1

[58] Public Service of Colorado, Public Utilities Commission of Colorado, Docket No. 14AL-0660E, Attachment RBH-6, 1

[59] Virginia Electric & Power, Virginia State Corporation Commission, Docket No. 2015-00027, Schedule 4, 1

[60] Potomac Electric Power, District of Columbia Public Service Commission, Exhibit PEPCO (D)-5, 1

[61] Duke Energy Progress, North Carolina Utilities Commission, Docket No. E-2, Sub 1142, Exhibit RBH-5, p. 1

other utility clients. However, such analysis is, obviously, suspect on many levels.

Mr. Hevert's Chart 1 shows Hevert market premiums tend to increase when interest rates decrease. In this case, Mr. Hevert is using a market risk premium of 10.28% to 11.05% at a time when 30-year Treasury bonds are yielding 3.06%. However, when one looks at Mr. Hevert's Chart 1, the risk premium for 30-year US Treasury bonds yielding 3.06% is approximately 7%, not the 10.28% to 11.05% as claimed by Mr. Hevert. In fact, a risk premium of anything over 8% is not even found on Mr. Hevert's Chart 1, thereby showing Mr. Hevert's own data prove his methods are biased to generate a high ROE for his utility clients.

Q. HAS MR. HEVERT CHANGED ANY OTHER ASPECT OF HIS CAPM RISK PREMIUM CALCULATIONS OVER THE YEARS?

A. Yes. In 2008, Mr. Hevert advocated using historical returns from the Ibbotson data series to determine a risk premium of 7.1%. In 2017, Mr. Hevert has abandoned his use of historical data and, instead, now advocates the use of a forecasted DCF model to forecast a risk premium which, in this case, is a market premium of 10.28% to 11.05%.

Q. WHAT EXPECTED MARKET RETURN DOES MR. HEVERT USE IN THE CAPM ANALYSIS HE EMPLOYS IN THIS CASE?

A. According to Hevert RBH-3, p. 1 and 7, Mr. Hevert uses expected market return estimates of 13.43% to 14.11% return on the market.

Q. DO YOU BELIEVE A 13.43% TO 14.11% RETURN ON THE MARKET IS A REASONABLE FORECAST?

A. No, not all. Anyone that follows the economy and markets knows that such a return forecast is simple fantasy, for the sole purpose of producing a high ROE. As I have shown previously in this testimony, most market forecasters are expecting returns to average approximately half of what Mr. Hevert is herein forecasting.

Q. IS THE COMPANY'S REQUESTED RETURN ON EQUITY IN THIS CASE RELATED TO ITS PENSION EXPENSE REQUEST?

A. Yes. The pension request of DEC in this case is directly related to the assumed return on equity the Company has used in its actuarial calculations. To be specific, the higher the assumed return on equity on the pension funds equity investments, the lower the pension amount that consumers must pay as part of this rate case proceeding.

Q. DO YOU HAVE ANY WAY TO DETERMINE THE EQUITY RISK PREMIUM THAT DUKE ENERGY, ITSELF, IS ESTIMATING FOR THE FORESEEABLE FUTURE?

A. Yes. In the current proceeding, DEC is asking for a revenue requirement to support a pension expense for its employees. Embedded in this pension request expense is an assumed market return on equity investments made by the Duke Energy pension fund actuarial consultant. The pension plan revenue requirement moves inversely relative to the assumed equity return on the market meaning that the higher the assumed equity return, the lower the pension plan funding requirements and vice versa. Table 19 below shows the expected market return of equities from Duke Energy's pension consultant, Towers Watson, and the weighted average equity return calculated from the Towers Watson actual asset allocation weightings:

Table 19: Expected Duke Equity Pension Returns [62]

	Policy Allocation	Towers Watson Expected Return (See Below)	Average Expected Return
US Equity - Large Cap	8.6%	8.50%	0.73%
US Equity - Small Cap	1.5%	8.77%	0.13%
Non-US Equity - Developed	6.4%	8.91%	0.57%
Non-US Equity - Emerging Market	1.6%	11.65%	0.19%
Global Equity	10.0%	8.73%	0.87%
Long Duration Bonds - Credit	58.6%	4.38%	2.57%
Long Duration Bonds - Govt	4.4%	3.58%	0.16%
Global Private Equity	3.0%	13.36%	0.40%
Hedge Funds	2.4%	6.10%	0.15%
Global Public Real Estate	0.5%	6.42%	0.03%
U.S. Private Real Estate	1.0%	6.42%	0.06%
Global Infrastructure	1.0%	7.45%	0.07%
Global Commodities	1.0%	7.45%	0.07%
	100.0%		6.01%
Expected Net Excess Return			0.30%
Enhanced Asset Allocation			0.15%
			6.46%
Assumed Expected Return (Rounded)			6.50%

The above table shows that DEC, in this rate case, is telling the Commission that the overall market returns for common equity investments will range from 13.36% for ultra-high risk Global Private Equity to 8.5% for large US Equities. I have calculated the weighted average expected return on equity forecasted by Duke Energy's pension consultant in the table below.

Table 20: Duke Energy Pension Equity Return

[62] Data Request response to CUCA 3-2 in Docket No. E-2, Sub 1142

	Policy Allocation	Weight	Towers Watson Expected Return (See Below)	Wgtd. Return
US Equity - Large Cap	8.6%	27.6%	8.50%	2.35%
US Equity - Small Cap	1.5%	4.9%	8.77%	0.43%
Non-US Equity - Developed	6.4%	20.6%	8.91%	1.83%
Non-US Equity - Emerging Market	1.6%	5.1%	11.65%	0.60%
Global Equity	10.0%	32.2%	8.73%	2.81%
Global Private Equity	3.0%	9.6%	13.36%	1.29%
Equity in Portfolio	31.1%		Wgtd. ROE	9.3%

The importance of Table 20 should not go unnoticed. In his application of the CAPM, Mr. Hevert testifies the overall market return on equity ranges from 10.28% to 11.3% (see Hevert Exhibit RBH-5, p. 1). Clearly, Mr. Hevert's analysis conflicts with the analysis of the Duke Energy consultant, Towers Watson.

(a) <u>**Changes in Hevert's Risk Premium Models**</u>

Q. HAS MR. HEVERT CHANGED THE MANNER IN WHICH HE CALCULATES HIS RISK PREMIUM MODEL IN THE LAST YEARS?

A. Yes. The inconsistencies that Mr. Hevert has exhibited in his application of the CAPM over the last years also exist in his use of the Risk Premium model.

Q. PLEASE EXPLAIN THE INCONSISTENCIES YOU HAVE FOUND IN MR. HEVERT'S RISK PREMIUM ANALYSES OVER HIS PAST TESTIMONIES.

A. On p. 42, l. 5, Mr. Hevert states the risk premium between ROEs granted by state regulators across the country and 30-year U.S. Treasury bond yields is 456 basis points. However, in his analysis in this case, Mr. Hevert increases that risk premium by another 250 basis points (706 as found in Exhibit RBH-6 less 456) by simply concluding that the 456 result is not "reasonable."

To be specific, in his pre-filed testimony, Mr. Hevert states the following:

> As Chart 1 illustrates, over time there has been a statistically significant, negative relationship between the 30-year Treasury yield and the Equity Risk Premium. Consequently, simply applying the long-term average Equity Risk Premium of 4.57 percent would significantly understate the Cost of Equity and produce results well below any reasonable estimate. Based on the regression coefficients in Chart 1, however, the implied ROE is between 9.97 percent and 10.33 percent (see Table 7 and Exhibit RBH-6).

In his 2010 testimony before the South Carolina Public Service Commission in the general rate case of South Carolina Electric & Gas, Mr. Hevert performed the same regression analysis as noted in this testimony in this case and found a risk premium of 588 basis points [63] to be appropriate. This case comparison shows that Mr. Hevert has, again, changed his current testimony from past testimonies whereby the end result produces an increase in the cost of equity for his utility clients.

To add insult to injury as exhibited by Mr. Hevert's lack of consistency throughout the years he has presented testimony on behalf of utility clients, the above statement is virtually identical to the same statement Mr. Hevert makes on p. 35, l. 5-11 of Mr. Hevert's Dominion NC Power testimony in Docket No. E-22, Sub 532. This duplication and inconsistency of testimonies is yet another reason to disallow the vast majority of Mr. Hevert's rate case fees in this case.

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[63] Hevert prefiled direct testimony before the South Carolina Public Service Commission in Docket No. SC PSC Docket 2009-489-E, p. 48

(i) <u>Changes in Hevert Multi-Stage DCF Model</u>

Q. HAS MR. HEVERT ALWAYS PRESENTED THE MULTI-STAGE DCF MODEL IN TESTIMONIES PRESENTED IN UTILITY RATE CASES?

A. No. Mr. Hevert added the Multi-Stage DCF model to his rate of return testimonies about two years ago.

Q. PLEASE CITE A RECENT CASE IN WHICH MR. HEVERT DID NOT PRESENT THE MULTI-STAGE DCF MODEL.

A. In 2015, Mr. Hevert was retained by Virginia Power in the Company's 2015 biennial rate proceeding (PUE-2015-00027) heard by the Virginia State Corporation Commission. The case was filed in the first quarter of 2015 and was heard in November of 2015. Mr. Hevert did not present the Multi-Stage DCF model in that 2015 case.

Q. WHEN DID YOU FIRST NOTICE MR. HEVERT ADDING THE MULTI-STAGE DCF MODEL TO HIS ANALYSES?

A. I first noticed Mr. Hevert using the Multi-Stage DCF model in the general rate case application of Public Service Company of Colorado that was heard in 2014. However, in 2015, as noted above, Mr. Hevert chose not to apply the Multi-Stage DCF model. He then went back to using the Multi-Stage DCF model in 2016 as evidenced by testimonies in Florida, North Carolina, and South Carolina. This lack of consistency begs the question as to why Mr. Hevert feels the need to change his testimonies so often.

Q. DO YOU SEE ANY INCONSISTENCY IN MR. HEVERT'S APPLICATION OF THE MULTI-STAGE DCF MODEL RELATIVE TO HIS OTHER METHODS?

A. Yes. In his application of the Multi-Stage DCF model, Mr. Hevert uses historical data to develop a GDP estimate. However, in the CAPM and Risk Premium models, he chooses not to use historical data. Not surprisingly, Mr. Hevert chooses to use data that supports his goal of producing a higher ROE for his utility clients.

Q. WHAT IS THE IMPACT OF USING HISTORICAL DATA IN THE MULTI-STAGE DCF MODEL BUT NOT DOING SO IN THE CAPM AND RISK PREMIUM MODELS?

A. Forecasted GDP growth is not as optimistic as historical GDP growth. If Mr. Hevert were to use forecasted GDP growth, his returns using the Multi-Stage DCF model would be lower than if he used historical GDP growth.

Q. WHAT GDP GROWTH ESTIMATE DID MR. HEVERT EMPLOY IN THIS CASE AND HOW DOES THAT ESTIMATE COMPARE TO US GOVERNMENT GDP ESTIMATES?

A. Mr. Hevert uses a 5.38% GDP estimate in his Multi-Stage DCF model. This GDP forecast uses a GDP historical growth rate of 3.22% and an inflation forecast of 2.09%.[64]

The US Government, on the other hand, sharply disagrees with Mr. Hevert's overly optimistic forecast of economic growth. For the period of 2017 through 2027, the Congressional Budget Office (CBO) is expecting GDP growth to be approximately 2.0%. [65] For the period of 2021-2026, the CBO expects growth to be approximately 2.0%. The following quote is taken from the June, 2017,

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64 Hevert, p. 32, l. 4-6

65 "Budget and Economic Outlook 2017-2027", Congressional Budget Office, 5

Budget and Economic Outlook 2017-2027 from the Congressional Budget Office.

> Economic growth is projected to remain modest, averaging slightly above 2.0 percent through 2018 and averaging somewhat below that rate for the rest of the period through 2027.[66]

As can be seen with the above quotes, the US government and Mr. Hevert have vastly different opinions on future US economic growth.

Mr. Hevert uses forecasted data in the CAPM. However, in the Multi-Stage DCF model, Mr. Hevert uses historical data. In both cases, not surprisingly, his "results" show a higher ROE for his utility clients than would be shown if his application methods were consistent.

Q. DID MR. HEVERT PROVIDE ANY REASON AS TO WHY HE HAS IGNORED LONG-TERM GDP ESTIMATES FROM HIGHLY RECOGNIZED AND RESPECTED SOURCES SUCH AS THE CONGRESSIONAL BUDGET OFFICE?

A. No.

(ii) <u>Changes in Weighting of Hevert Cost of Capital Methods</u>

Q. HAS MR. HEVERT BEEN CONSISTENT IN THE WEIGHTING OF THE RESULTS OF HIS COST OF CAPITAL METHODS FROM CASE TO CASE?

A. No. In comparison to past cases, Mr. Hevert has changed the weights he has placed on the methods.

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66 id

Q. CAN YOU PROVIDE US AN EXAMPLE OF THE CHANGE IN MR. HEVERT'S WEIGHTING OF HIS COST OF CAPITAL METHODS?

A. Yes. The following Q&A is from Mr. Hevert's 2010 South Carolina Electric & Gas testimony:

> **Q. DID YOU UNDERTAKE ANY ADDITIONAL ANALYSES TO SUPPORT YOUR DCF MODEL RESULTS?**
>
> A. Yes. As noted earlier, I also used the CAPM and the Risk Premium approach as a means of assessing the reasonableness of my [Constant Growth] DCF results.[67] (insertion added)

However, in the current DEC proceeding, Mr. Hevert now attempts to dismiss the Constant Growth DCF model. To be specific, he states:

> Because it is important to reflect the results of different models, and the mean and mean low Constant Growth DCF results are far removed from recently authorized returns, I concluded that they should be given less weight than other methods in determining the Company's ROE.[68]

So, in prior cases, Mr. Hevert stated that he used the CAPM and Risk Premium models to assess the reasonableness of his DCF models. However, since those earlier cases as cited above, Mr. Hevert has drastically changed his application of the CAPM and Risk Premium models such that the changes result in higher cost estimates. Unfortunately for this Commission, the machinations espoused by Mr. Hevert complicate and cloud a very simple fact that the cost of capital has gone down dramatically over the years, a fact that Mr. Hevert finds difficult to acknowledge.

67 South Carolina Public Service Commission Docket No. 2009-489-E, Hevert Testimony, 38

68 Hevert prefiled direct, 27-28

Q. DO YOU AGREE WITH MR. HEVERT THAT THE CURRENT MARKET IS SO DIFFERENT FROM PAST MARKETS THAT ANALYSTS SHOULD CHANGE THEIR COST OF CAPITAL METHODOLOGIES FROM CASE-TO-CASE IN VARIOUS JURISDICTIONS?

A. No. In the investing community, many consider the four most dangerous words to be: "this time is different." There is no reason to doubt that a model that has worked well in the past should not work well in current times. Mr. Hevert's argument that the current financial times are different than in the past ignores the fact that we have experienced "different" financial times in the past as well. Situations like the Great Depression, WWII, 9-11, the Great Recession, and the multitude of other recessions experienced by this country have all been "different" in manners not unlike the current quantitative easing of the Federal Reserve. Mr. Hevert is attempting to convince state regulators that current times are unprecedented and methods he used in the past are no longer valid. Such a position is simply illogical and unabashedly biased.

Q. HAS ANY STATE REGULATORY BODY RECENTLY ADDRESSED THE SHIFTING SANDS OF MR. HEVERT'S TESTIMONIES?

A. Yes. Mr. Hevert filed testimony on behalf of Dominion Virginia State Corporation Commission (Virginia SCC) in Case No. PUR-2017-00038. Mr. Hevert's recommendation was that Dominion Virginia Power (DVP) should be granted a 10.5% ROE. The Virginia SCC weighed the evidence and granted DVP a 9.2% ROE. In regard to Mr. Hevert's testimony, the Virginia SCC found the following:

1. Mr. Hevert's proposed cost of equity of 10.25% to 10.75% did not represent the actual cost of equity in the marketplace nor a reasonable ROE for DVP; [69]
2. Mr. Hevert's recommended ROE of 10.5% is not supported by reasonable growth rates, DCF methods or risk premium analyses; [70]
3. Mr. Hevert's application of the CAPM is flawed and his application of the Bond Yield Plus Risk Premium model contains similar flaws as his CAPM analysis; [71] and
4. Mr. Hevert's claim of Dominion deserving a 10.5% ROE due to certain business was summarily rejected as the Virginia SCC noted that the majority of DVP's future capex could be recovered through automatic revenue adjustment clauses (RACs).[72]

10. Cost of Service Study and Rate Design

Q. MR. O'DONNELL, WHAT IS A COST OF SERVICE STUDY AND WHY ARE THE RESULTS OF SUCH A STUDY RELEVANT IN THIS PROCEEDING?

A. A cost of service study is the starting point for any rate design analysis. Before any changes are made to customer classes, the current cost of serving each customer class and the return which the Company earns on service to that class must be determined. Once these costs have been calculated, rates for each class can be changed in order to bring the class rates of return in line with the costs incurred in serving each class.

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[69] Virginia SCC Final Order in Case No. PUR-2017-0003, Nov. 29, 2017, 4

[70] id

[71] Id, 5

[72] Id, 6

Q. SHOULD AN ANALYST LOOK AT FACTORS OTHER THAN CUSTOMER CLASS RATES OF RETURN WHEN EXAMINING HOW TO ADJUST RATES?

A. Yes. The analyst should also consider how the particular rate increase may impact the service territory of the utility and the long-term impact of the rate change. For example, a rate increase to a manufacturing customer on the verge of financial collapse may well be the last straw that pushes the employer out of the state, or worse, totally out of business. When that manufacturer closes its door, the load of that customer is probably gone forever meaning that rates for all other customers must concurrently increase to keep the utility whole.

Q. PLEASE EXPLAIN WHY RATES MUST INCREASE WHEN A MANUFACTURER CEASES OPERATIONS.

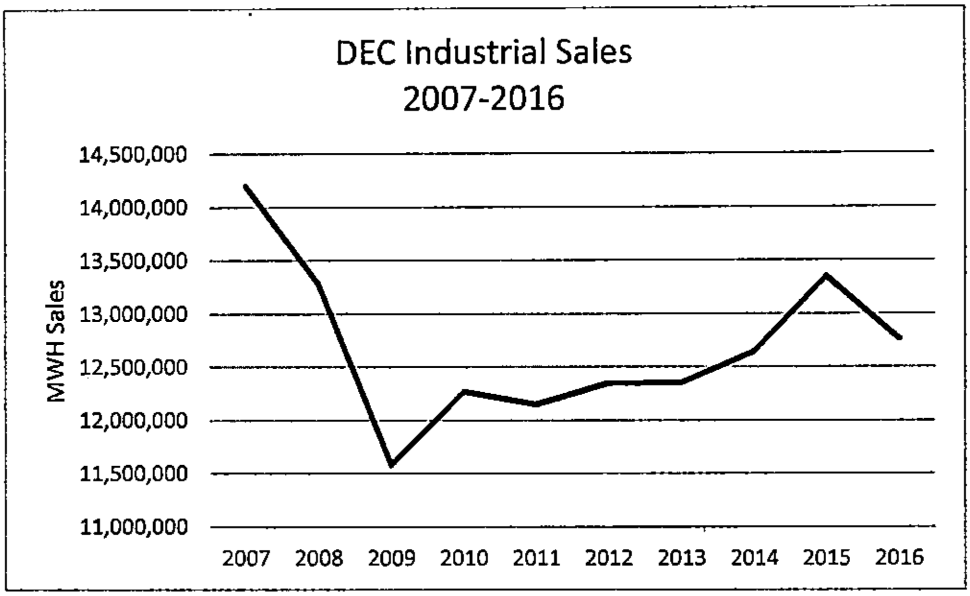
A. Regulation assures a utility the opportunity to recover its prudently incurred costs. If a large customer leaves the utility system, the remaining costs must be allocated amongst all other customers and shared equitably.

In Table 6 above, I provided an example of how such a cost increase were to occur if DEC were to lose its entire industrial base. As I showed in that table, all other remaining customers would realize a 7.54% rate hike if DEC lost its entire industrial base. This rate hike scenario gets even worse when the multitude of upcoming Duke rate cases is factored into this loss of industrial load.

Q. WHAT HAS BEEN THE TREND FOR INDUSTRIAL SALES IN DEC SERVICE TERRITORY OVER THE PAST TEN YEARS?

A. The overall trend in industrial sales in the DEC over the past ten years has been a steady decrease in sales. Chart 6 below provides the annual industrial MWH sales for DEC over the past ten years.

Chart 6: DEC Industrial Sales



Source for data: SNL.com

As one can see from the above graph, industrial sales in the DEC service territory never recovered from the 2008 recession. The above graph is evidence of the need for the JRR. It is also evidence that Duke should work particularly hard at controlling its costs, perhaps starting with its rate case expenses.

Q. WHAT IS A SUMMER COINCIDENT PEAK (CP) COST OF SERVICE STUDY?

A. A summer coincident peak (SCP) cost of service study (COSS) is a study that allocates generation costs based on the load of each customer class at the time of the single largest peak load placed on the electric utility's system during a given year. This one allocation will have the single largest impact on the resulting customer class rates of return from a COSS

Q. DO YOU AGREE THAT A SCP COSS IS THE MOST APPROPRIATE ALLOCATION METHODOLOGY FOR USE BY DEC?

A. Yes. Historically, the DEC electric system has been a summer peaking system. Since electric systems are typically built to meet the single largest peak demand placed on the electric system in any given year, the SCP COSS is the most representative model of how the generation system is used in any given year.

I am well aware that DEC has recently sustained winter peaks as opposed to summer peaks. The concept of the coincident peak methodology really does not change due to the seasons. The CP is the highest peak recorded by the electric system, regardless of the time of the year the peak occurred. However, in this case, I am willing to accept the Duke proposed summer CP model. The reason being is this issue has been the source of great contention between parties for several years. CUCA is not going to argue the issue in this case but, instead, reserves the right to argue this issue in future rate cases if/when Duke continues to sustain more winter peaks.

Q. DOES THE COINCIDENT PEAK METHOD REFLECT THE MANNER IN WHICH DEC'S CUSTOMERS USE ELECTRICITY?

A. Yes. DEC has three major customer classes: residential, commercial, and industrial. Of these three classes, the residential class is the most temperature-sensitive and time-sensitive class. Put simply, when the temperature rises outside the home, residential consumers respond by running their air conditioners more frequently. The time at which residential consumers use the most electricity is, typically, the late afternoon hours of a hot summer day when workers come home from work. To accommodate the need for electricity, DEC must ramp up its more expensive generating plants to meet this summer peak demand.

Industrial consumers, on the other hand, keep their energy consumption relatively level as these customers are much less sensitive to temperature fluctuations than are residential consumers. Furthermore, it is often very costly for a large manufacturer to ramp up and down its manufacturing operations due to the stresses that such variations place on manufacturing equipment.

In the current case, the rates proposed by DEC are based upon the coincident peak (CP) cost allocation methodology that does reflect the fact that the generation plant constructed by the Company is built to meet the Company's peak demand. For the reasons set forth above, DEC's use of the summer coincident peak allocation methodology is appropriate for use in the Company's cost of service study in this proceeding.

Q. DID DEC FILE ANOTHER COSS METHODOLOGY IN THIS CASE?

A. Yes. DEC also filed the summer winter peak and average (SWPA) COSS in this case.

Q. DO YOU BELIEVE THE SWPA COSS METHODOLOGY IS APPROPRIATE FOR USE IN SETTING RATES?

A. No. The SWPA methodology allocates 50% of production costs to energy and 50% to demand. The theory behind this allocation is that it reflects the annual use of the generation assets as opposed to the peak use of the generation assets. In my view, such an allocation is inappropriate for use in DEC where the peaks are so distinct. The DEC electric system was designed to meet a single annual peak and, as such, the allocation of production costs should be based on the SCP.

V. RECOMMENDATIONS AND CONCLUSION

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSIS IN THIS CASE.

A. I began my analysis in this case by examining the DEC rates relative to utilities across the United States and, in particular, the southeast. My conclusion is that, contrary to what DEC wants this Commission to believe, its industrial rates:

- Are currently just slightly below the national average;
- will be approximately equal to the national average if the Commission approves the requested rate increase in its case;
- are above the industrial costs of neighboring states with which we compete for manufacturing jobs; and
- will be grossly uncompetitive if Duke is allowed to move forward with its grid modernization efforts, herein referred to as Project GRIM.

With regard to coal ash, I have provided evidence in this proceeding that the Dan River spill caused the passage of the Coal Ash Management Act (CAMA) in North Carolina. Duke's argument to the contrary is nonsensical and opposed by members of both parties at the NC General Assembly. [73] After the coal ash spill, the federal government investigated the actions of Duke Energy at its coal ash ponds in North Carolina and subsequently charged the Company with nine violations of the Clean Water Act. Duke and the federal government reached a plea deal where Duke admitted guilt and was fined $102 million.

I agree that consumers in North Carolina should pay for coal ash costs that are the result of normal operations. However, Duke's admission of guilt to imprudent operation of its coal ash ponds resulted in the passage of CAMA. My analysis attempted to determine a dividing line between the CAMA costs and the EPA's CCR costs. My recommendation is the Commission disallow 75% of Duke's requested coal ash costs in this case and in all future cases so that North

[73] http://www.wral.com/seeking-rate-increase-duke-energy-dodges-link-between-coal-ash-spill-and-coal-ash-bill/17145054/

Carolina consumers only have to pay the CCR – or normal course of operations – coal ash costs.

I recommend the Commission accept the Company's Job Retention Rider (JRR). Failure to save manufacturing jobs in North Carolina will result in permanent rate hikes far in excess of the cost of the JRT in this case.

The Commission should reduce the rate case expenses for DEC Witnesses Hevert to no more than the rate case expense for the Public Staff rate of return witness. DEC is still free to pay Mr. Hevert any amount they so choose. My recommendation applies only to the amount of the rate case expenses that are allowed into rates in this case.

I recommend the Commission grant DEC a return on equity of 9.0% and the capital structure be set at 50% common equity and 50% long-term debt. My overall recommended rate of return is 6.87%.

I have further reviewed the testimony as presented by Company Witness Hevert in this proceeding. Below is my list of findings in regard to his testimony:

- Mr. Hevert's rate of return analysis presented in the current DEC case is out-of-touch with the consensus forecasts of mainstream investment analysts;
- Mr. Hevert's historically conflicting testimonies show that he has changed his testimonies frequently in ways that consistently resulted in higher returns on equity for his utility clients and, therefore, his recommendations are upwardly biased; and
- The recent findings of the Virginia State Corporation Commission in regard to Mr. Hevert's testimony are accurate and telling.

Lastly, the Company's proposed summer (or single) coincident peak (SCP) cost of service study should be adopted for ratemaking purposes in this proceeding.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

Duke Energy Carolinas

Docket No. E-7, Sub 1146

Comparable Group and Duke Energy Constant Growth DCF Results

Company	DCF Results														
	13 Wk. Avg. Dividend Yield	4 Wk. Avg. Dividend Yield	Current Dividend Yield	Value Line									Plowback Growth Rate	CFRA Forecasted EPS	Schwab Forecasted EPS
				10 Year			5 Year			Forecasted					
				EPS	DPS	BPS	EPS	DPS	BPS	EPS	DPS	BPS			
ALLETE Inc	2.8%	2.9%	3.0%	3.5%	7.5%	5.5%	7.0%	2.5%	6.0%	5.0%	4.2%	4.0%	3.2%	8.0%	—
Alliant Energy Corp	2.9%	2.9%	2.9%	5.0%	7.5%	4.0%	6.5%	6.5%	4.5%	6.0%	4.5%	4.0%	3.5%	6.0%	7.1%
Ameren Corp	3.0%	3.0%	3.1%	-1.5%	-4.0%	-1.0%	-1.5%	1.5%	-2.5%	6.0%	4.5%	4.0%	3.3%	6.0%	7.2%
American Electric Power Co Inc	3.3%	3.3%	3.4%	3.0%	4.0%	4.5%	5.0%	4.5%	4.5%	4.0%	5.0%	3.5%	4.4%	1.0%	—
Avista	2.8%	2.9%	2.9%	6.5%	9.5%	4.0%	3.5%	6.5%	4.5%	4.0%	4.0%	3.5%	4.4%	6.6%	—
Black Hills Corp	3.0%	3.3%	3.2%	3.5%	2.5%	2.5%	11.0%	2.5%	1.5%	7.5%	5.0%	5.5%	2.6%	5.0%	3.4%
CMS Energy Corp	2.9%	2.9%	3.0%	8.5%	—	3.0%	8.5%	11.5%	4.5%	6.5%	6.5%	6.5%	4.4%	8.0%	7.4%
DTE Energy Co	3.2%	3.2%	3.3%	5.5%	3.5%	4.0%	6.0%	5.5%	4.0%	6.0%	7.0%	4.5%	5.1%	4.0%	5.2%
IDACORP Inc	2.5%	2.5%	2.5%	7.0%	5.0%	5.0%	5.5%	10.0%	5.5%	3.5%	7.0%	4.0%	3.9%	3.0%	2.7%
Northwestern Corp	3.6%	3.5%	3.6%	—	9.5%	5.0%	7.0%	6.0%	8.0%	4.5%	5.0%	3.5%	3.7%	2.2%	1.0%
OGE Energy Corp	3.8%	4.1%	4.2%	6.0%	4.5%	8.0%	3.5%	7.5%	7.5%	6.0%	9.0%	3.5%	3.6%	8.0%	5.8%
Otter Tail Corp	2.8%	2.8%	2.9%	-0.5%	1.0%	—	25.0%	0.5%	-1.5%	7.0%	2.0%	6.5%	2.9%	na	—
Pinnacle West Capital Corp	3.1%	3.1%	3.2%	3.5%	2.5%	2.0%	6.5%	3.0%	4.0%	5.5%	5.5%	4.0%	3.7%	6.0%	5.4%
PNM Resources Inc	2.4%	2.4%	2.5%	-0.5%	0.5%	1.0%	11.5%	10.0%	2.5%	7.5%	9.5%	2.5%	3.4%	8.0%	5.8%
Portland General Electric Co	3.0%	2.9%	3.0%	7.0%	13.5%	3.0%	5.5%	3.0%	3.5%	6.0%	6.0%	3.5%	3.6%	5.0%	4.0%
Southern Co.	4.6%	4.7%	4.8%	3.0%	4.0%	5.0%	3.0%	3.5%	4.0%	3.5%	3.5%	3.0%	3.0%	3.0%	3.2%
WEC Energy Group Inc	3.2%	3.2%	3.3%	8.5%	15.0%	8.0%	6.5%	16.0%	9.0%	6.0%	6.5%	5.0%	3.7%	5.6%	5.6%
Xcel Energy Inc	3.0%	3.0%	3.0%	5.0%	4.0%	4.5%	6.0%	5.0%	4.5%	4.5%	6.0%	4.0%	3.7%	6.0%	5.3%
Average	**3.1%**	**3.1%**	**3.2%**	**4.3%**	**5.3%**	**4.0%**	**7.0%**	**5.9%**	**4.1%**	**5.6%**	**5.6%**	**4.2%**	**3.7%**	**5.4%**	**4.9%**
Duke Energy Corp	4.1%	4.2%	4.3%	3.5%	-	-0.5%	0.5%	2.5%	3.0%	4.5%	4.5%	1.5%	1.4%	3.0%	2.9%

Source: Value Line Investment Survey, Nov 17, 2017; December 15, 2017; Oct. 27, 2017

Exhibit KWO-1

Duke Energy Carolinas 2017

Docket No. E-7, Sub 1146

Comparable Group and Duke Energy Plowback Growth Rate

Company	% Retained to Common Equity				
	2015	2016	2017E	2020E/2022E	Average
ALLETE Inc	3.6%	2.8%	3.0%	3.5%	3.2%
Alliant Energy Corp	3.6%	2.8%	3.5%	4.0%	3.5%
Ameren Corp	2.5%	3.3%	3.5%	4.0%	3.3%
American Electric Power Co Inc	3.9%	5.5%	3.5%	4.5%	4.4%
Avista	3.9%	5.5%	3.5%	4.5%	4.4%
Black Hills Corp	2.3%	3.0%	2.0%	3.0%	2.6%
CMS Energy Corp	3.8%	3.3%	5.5%	5.0%	4.4%
DTE Energy Co	5.2%	4.8%	5.0%	5.5%	5.1%
IDACORP Inc	3.4%	3.7%	5.0%	3.5%	3.9%
Northwestern Corp	3.0%	4.1%	3.5%	4.0%	3.7%
OGE Energy Corp	4.0%	3.3%	3.5%	3.5%	3.6%
Otter Tail Corp	2.0%	2.1%	3.0%	4.5%	2.9%
Pinnacle West Capital Corp	3.9%	3.5%	3.5%	4.0%	3.7%
PNM Resources Inc	3.3%	2.8%	4.0%	3.5%	3.4%
Portland General Electric Co	3.3%	3.5%	3.5%	4.0%	3.6%
Southern Co	3.1%	2.5%	3.0%	3.5%	3.0%
WEC Energy Group Inc	2.1%	3.5%	3.5%	4.0%	3.7%
Xcel Energy Inc	4.3%	4.0%	4.0%	3.5%	3.7%
Average					
Duke	1.5%	0.6%	1.5%	2.0%	1.4%

Source: Value Line Investment Survey, Nov 17, 2017, December 15, 2017, Oct. 27, 2017

Duke Energy Carolinas 2017
Docket No. E-7, Sub 1146
Comparable Group and Duke Earned Returns on Equity

Company	% Return on Common Equity			
	2015	2016	2017E	2020E/2022E
ALLETE Inc	9.0%	8.2%	8.5%	9.0%
Alliant Energy Corp	10.2%	9.7%	10.0%	12.0%
Ameren Corp	8.3%	9.2%	9.5%	10.0%
American Electric Power Co Inc	9.9%	11.9%	10.0%	11.0%
Avista	7.7%	8.3%	7.0%	8.5%
Black Hills Corp	8.8%	8.7%	11.0%	10.5%
CMS Energy Corp	13.3%	13.0%	13.5%	13.5%
DTE Energy Co	9.1%	9.6%	11.5%	10.5%
IDACORP Inc	9.5%	9.2%	9.5%	9.0%
Northwestern Corp	8.6%	9.8%	9.5%	10.0%
OGE Energy Corp	10.2%	9.8%	10.5%	12.0%
Otter Tail Corp	9.7%	9.3%	10.0%	10.0%
Pinnacle West Capital Corp	9.5%	9.2%	9.5%	10.5%
PNM Resources Inc	7.1%	7.0%	8.5%	9.0%
Portland General Electric Co	7.6%	8.2%	8.5%	9.5%
Southern Co.	12.6%	11.0%	12.5%	13.0%
WEC Energy Group Inc	7.4%	10.5%	11.0%	11.5%
Xcel Energy Inc	10.0%	10.2%	10.5%	10.5%
Average	9.4%	9.6%	10.1%	10.6%
Duke Energy	7.2%	6.2%	7.0%	8.5%

Source: Value Line Investment Survey, Nov. 17, 2017; December 15, 2017; Oct. 27, 2017

Duke Energy Carolinas
Docket No. E-7 Sub 1146
CAPM Results

Comparable Group

	Risk-Free Rate	Beta	Equity Risk	Equity Cost
Treasury - Maximum	3.20%	0.72	4.0%	6.1%
Treasury - Average	2.89%	0.72	4.0%	5.8%
Treasury - Minimum	2.66%	0.72	4.0%	5.5%

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Treasury - Maximum	3.20%	0.72	6.0%	7.5%
Treasury - Average	2.89%	0.72	6.0%	7.2%
Treasury - Minimum	2.66%	0.72	6.0%	7.0%

Duke

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Treasury - Maximum	3.20%	0.60	4.0%	5.6%
Treasury - Average	2.89%	0.60	4.0%	5.3%
Treasury - Minimum	2.66%	0.60	4.0%	5.1%

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Treasury - Maximum	3.20%	0.60	6.0%	6.8%
Treasury - Average	2.89%	0.60	6.0%	6.5%
Treasury - Minimum	2.66%	0.60	6.0%	6.3%

Duke Energy Carolina 2017
Docket No. E-7, Sub 1146

Sorted Coal Ash by ARO

Ranking	Utility	Total Coal Ash AROs	Nameplant Cap. Of Coal Plants	Average Age of Coal Plants	Calculated MWHs from Generation 65% cap factor	Calculated ARO per MWH of Gen.
1	Duke Energy Progress, LLC	$2,228,000	3,735	43	914,484,870	$0.002436
2	Duke Energy Carolinas, LLC	$2,032,000	7,289	42	1,743,173,687	$0.001166
3	Georgia Power Company	$1,291,000	6,466	43	1,583,094,507	$0.000815
4	Duke Energy Indiana, LLC	$866,242	4,368	42	1,044,569,766	$0.000829
5	Virginia Electric and Power Com	$583,000	4,247	40	967,319,496	$0.000603
6	Kansas City Power & Light Comp	$278,043	2,768	38	598,820,329	$0.000464
7	PacifiCorp	$214,786	6,908	42	1,652,058,299	$0.000130
8	DTE Electric Company	$212,000	6,856	46	1,795,643,555	$0.000118
9	Alabama Power Company	$199,000	6,018	40	1,370,673,346	$0.000145
10	Dayton Power and Light Compa	$135,159	2,355	40	536,324,693	$0.000252
11	Mississippi Power Company	$128,000	548	38	118,636,768	$0.001079
12	Appalachian Power Company	$127,098	4,608	44	1,154,379,695	$0.000110
13	ALLETE (Minnesota Power)	$93,304	961	43	235,268,678	$0.000397
14	Southwestern Electric Power Co	$83,454	2,751	30	469,949,735	$0.000178
15	Nevada Power Company	$82,938	272	42	65,108,043	$0.001274
16	Kansas Gas and Electric Compan	$74,300	1,221	40	278,094,960	$0.000267
17	Oklahoma Gas and Electric Com	$69,576	2,854	37	601,275,012	$0.000116
18	Kentucky Power Company	$62,994	816	46	213,808,561	$0.000295
19	Arizona Public Service Company	$56,000	1,909	45	489,025,204	$0.000115
20	Public Service Company of Okla	$53,413	585	37	123,343,542	$0.000433
21	Kentucky Utilities Company	$49,000	3,769	38	815,586,126	$0.000060
22	Tampa Electric Company	$44,879	1,956	39	434,338,889	$0.000103
23	KCP&L Greater Missouri Operati	$37,998	992	39	220,289,472	$0.000172
24	Monongahela Power Company	$37,509	3,216	46	842,271,626	$0.000045
25	Tucson Electric Power Company	$32,655	1,687	37	355,441,174	$0.000092
26	Gulf Power Company	$29,000	1,906	42	455,851,960	$0.000064
27	Southwestern Public Service Co	$28,663	2,216	36	454,203,547	$0.000063
28	Westar Energy (KPL)	$28,018	2,154	40	490,640,592	$0.000057
29	Idaho Power Co.	$26,257	1,154	39	256,164,234	$0.000103
30	Public Service Company of New	$23,529	559	53	168,756,494	$0.000139
31	Empire District Electric Compan	$23,517	464	31	81,856,602	$0.000287
32	Portland General Electric Comp	$23,000	889	35	177,204,682	$0.000130
33	Duke Energy Florida, LLC	$19,000	2,443	40	556,349,352	$0.000034
34	Indiana Michigan Power Compa	$18,079	1,488	34	288,001,153	$0.000063
35	Public Service Company of New	$17,724	1,073	41	250,402,760	$0.000071
36	Entergy Mississippi, Inc.	$8,722	450	34	87,118,200	$0.000100
37	Otter Tail Power Company	$8,341	533	43	130,422,437	$0.000064
38	Cleco Power LLC	$6,933	1,232	18	126,224,023	$0.000055
39	Wheeling Power Company	$6,848	816	46	213,808,561	$0.000032
40	Entergy Texas, Inc.	$6,470	293	35	58,459,729	$0.000111
41	Ohio Power Company	$1,654	476	62	168,179,009	$0.000010
42	Entergy Louisiana, LLC	$0	399	35	79,544,611	$0.000000
43	Florida Power & Light Company	$0	1,347	27	207,141,969	$0.000000
44	Entergy Arkansas, Inc.	$0	1,310	36	268,426,548	$0.000000

Appendix A

Kevin W. O'Donnell, CFA

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Kevin W. O'Donnell, is the founder of Nova Energy Consultants, Inc. in Cary, NC. Mr. O'Donnell's academic credentials include a B.S. in Civil Engineering - Construction Option from North Carolina State University as well as a MBA in Finance from Florida State University. Mr. O'Donnell is also a Chartered Financial Analyst (CFA).

Mr. O'Donnell has over thirty-one years of experience working in the electric, natural gas, and water/sewer industries. He is very active in municipal power projects and has assisted numerous southeastern U.S. municipalities cut their wholesale cost of power by as much as 67%. On Dec. 12, 1998, ***The Wilson Daily Times*** made the following statement about O'Donnell.

> **Although we were skeptical of O'Donnell's efforts at first, he has shown that he can deliver on promises to cut electrical rates.**

As of the start of 2015, Mr. O'Donnell has completed over 25 wholesale power projects for municipal and university-owned electric systems throughout North and South Carolina. In May of 1996 Mr. O'Donnell testified before the U.S. House of Representatives, Committee on Commerce, Subcommittee on Energy and Power regarding the restructuring of the electric utility industry.

Mr. O'Donnell has appeared as an expert witness in 91 regulatory proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Virginia Corporation Commission, the Minnesota Public Service Commission, the New Jersey Board of Public Utilities, the Colorado Public Service Commission, District of Columbia Public Service Commission, the Maryland Public Service Commission, the Wisconsin Public Service Commission, and the Florida Public Service Commission. His area of expertise has included rate design, cost of service, rate of return, capital structure, nuclear decommissioning, natural gas expansion feasibility studies, fuel adjustments, merger transactions, cogeneration studies, holding company applications, as well as numerous other accounting, financial, and utility rate-related issues.

Mr. O'Donnell is the author of the following two articles: "Aggregating Municipal Loads: The Future is Today" which was published in the Oct. 1, 1995 edition of *Public Utilities Fortnightly;* and "Worth the Wait, But Still at Risk" which was published in the May 1, 2000 edition of *Public Utilities Fortnightly.* Mr. O'Donnell is also the co-author of "Small Towns, Big Rate Cuts" which was published in the January, 1997 edition of *Energy Buyers Guide.* All of these articles discuss how rural electric systems can use the wholesale power markets to procure wholesale power supplies.

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
1985	Public Service Company of NC	NC	G-5, Sub 200	Public Staff of NCUC	Return on equity, capital structure
1985	Piedmont Natural Gas Company	NC	G-9, Sub 251	Public Staff of NCUC	Return on equity, capital structure
1986	General Telephone of the South	NC	P-19, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1987	Public Service Company of NC	NC	G-5, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1988	Piedmont Natural Gas Company	NC	G-9, Sub 278	Public Staff of NCUC	Return on equity, capital structure
1989	Public Service Company of NC	NC	G-5, Sub 246	Public Staff of NCUC	Return on equity, capital structure
1990	North Carolina Power	NC	E-22, Sub 314	Public Staff of NCUC	Return on equity, capital structure
1991	Duke Energy	NC	E-7, Sub 487	Public Staff of NCUC	Return on equity, capital structure
1992	North Carolina Natural Gas	NC	G-21, Sub 306	Public Staff of NCUC	Natural gas expansion fund
1992	North Carolina Natural Gas	NC	G-21, Sub 307	Public Staff of NCUC	Natural gas expansion fund
1995	Penn & Southern Gas Company	NC	G-3, Sub 186	Public Staff of NCUC	Return on equity, capital structure
1995	North Carolina Natural Gas	NC	G-21, Sub 334	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1995	Carolina Power & Light Company	NC	E-2, Sub 680	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1995	Duke Power	NC	E-7, Sub 559	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1996	Piedmont Natural Gas Company	NC	G-9, Sub 378	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Piedmont Natural Gas Company	NC	G-9, Sub 382	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Public Service Company of NC	NC	G-5, Sub 356	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Cardinal Extension Company	NC	G-39, Sub 0	Carolina Utility Customers Assoc.	Capital structure, cost of capital
1997	Public Service Company of NC	NC	G-5, Sub 327	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Natural gas transporation rates
1999	Public Service Company of NC/SCANA	NC	G-5, Sub 400	Carolina Utility Customers Assoc.	Merger case
1999	Public Service Company of NC/SCANA	NC	G-43	Carolina Utility Customers Assoc.	Merger Case
1999	Carolina Power & Light Company	NC	E-2, Sub 753	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	G-21, Sub 387	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	P-708, Sub 5	Carolina Utility Customers Assoc.	Holding company application
2000	Piedmont Natural Gas Company	NC	G-9, Sub 428	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2000	NUI Corporation	NC	G-3, Sub 224	Carolina Utility Customers Assoc.	Holding company application
2000	NUI Corporation/Virginia Gas Compan	NC	G-3, Sub 232	Carolina Utility Customers Assoc.	Merger application
2001	Duke Power	NC	E-7, Sub 685	Carolina Utility Customers Assoc.	Emission allowances and environmental compliance costs
2001	NUI Corporation	NC	G-3, Sub 235	Carolina Utility Customers Assoc.	Tariff change request.
2001	Carolina Power & Light Company/Prog	NC	E-2, Sub 778	Carolina Utility Customers Assoc.	Asset transfer case
2001	Duke Power	NC	E-7, Sub 694	Carolina Utility Customers Assoc.	Restructuring application
2002	Piedmont Natural Gas Company	NC	G-9, Sub 461	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2002	Cardinal Pipeline Company	NC	G-39, Sub 4	Carolina Utility Customers Assoc.	Cost of capital, capital structure
2002	South Carolina Public Service Commiss	SC	2002-63-G	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2003	Piedmont Natural Gas/North Carolina I	NC	G-9, Sub 470	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina I	NC	G-9, Sub 430	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina I	NC	E-2, Sub 825	Carolina Utility Customers Assoc.	Merger application
2003	Carolina Power & Light Company	NC	E-2, Sub 833	Carolina Utility Customers Assoc.	Fuel case
2004	South Carolina Electric & Gas	SC	2004-178-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2005	Carolina Power & Light Company	NC	E-2, Sub 868	Carolina Utility Customers Assoc.	Fuel case

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
2005	Piedmont Natural Gas Company	NC	G-9, Sub 499	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2005	South Carolina Electric & Gas	SC	2005-2-E	South Carolina Energy Users Committee	Fuel application
2005	Carolina Power & Light Company	SC	2006-1-E	South Carolina Energy Users Committee	Fuel application
2006	IRP in North Carolina	NC	E-100, Sub 103	Carolina Utility Customers Assoc.	Submitted rebuttal testimony in investigation of IRP in NC.
2006	Piedmont Natural Gas Company	NC	G-9, Sub 519	Carolina Utility Customers Assoc.	Creditworthiness issue
2006	Public Service Company of NC	NC	G-5, Sub 481	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2006	Duke Power	NC	E-7, 751	Carolina Utility Customers Assoc.	App to share net revenues from certain wholesale pwr trans
2006	South Carolina Electric & Gas	SC	2006-192-E	South Carolina Energy Users Committee	Fuel application
2007	Duke Power	NC	E-7, Sub 790	Carolina Utility Customers Assoc.	Application to construct generation
2007	South Carolina Electric & Gas	SC	2007-229-E	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2008	South Carolina Electric & Gas	SC	2008-196-E	South Carolina Energy Users Committee	Base load review act proceeding
2009	Western Carolina University	NC	E-35, Sub 37	Western Carolina University	Rate of return, accounting, rate design, cost of service
2009	Duke Power	NC	E-7, Sub 909	Carolina Utility Customers Assoc.	Cost of service, rate design, return on equity, capital structure
2009	South Carolina Electric & Gas	SC	2009-261-E	South Carolina Energy Users Committee	DSM/EE rate filing
2009	Duke Power	SC	2009-226-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2009	Tampa Electric	FL	080317-EI	Florida Retail Federation	Return on equity, capital structure
2010	Duke Power	SC	2010-3-E	South Carolina Energy Users Committee	Fuel application - assisted in settlement
2010	South Carolina Electric & Gas	SC	2009-489-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2010	Virginia Power	VA	PUE-2010-00006	Mead Westvaco	Rate design
2011	Duke Energy	SC	2011-20-E	South Carolina Energy Users Committee	Nuclear construction financing
2011	Northern States Power	MN	E002/GR-10-971	Xcel Large Industrials	Return on equity, capital structure
2011	Virginia Power	VA	PUE-2011-0027	Mead Westvaco	Capital structure, revenue requirement
2011	Duke Energy	NC	E-7, Sub 989	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2011	Duke Energy	SC	2011-271-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2011	Dominion Virginia Power	VA	PUE-2011-00073	Mead Westvaco	Rate design
2012	Town of Smithfield/Partners Equity Gr	NC	ES-160, Sub 0	Partners Equity Group	Rate design, asset valuation
2012	Florida Power & Light	FL	120015-EI	Florida Office of Public Counsel	Capital structure
2012	South Carolina Electric & Gas	SC	2012-218-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2013	Progress Energy Carolinas	NC	E-2, Sub 1023	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2013	Duke Energy Carolinas	NC	E-7, Sub 1026	Carolina Utility Customers Assoc.	Rate design
2013	Jersey Central Power & Light	NJ	BPU ER12111052	Gerdau Ameristeel	Return on equity, capital structure
2013	Duke Energy Carolinas	SC	2013-59-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2013	Tampa Electric	FL	130040-EI	Florida Office of Public Counsel	Capital structure and financial integrity
2013	Piedmont Natural Gas	NC	G-9, Sub 631	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2014	Dominion Virginia Power	VA	PUE-2014-00033	Mead Westvaco	Recoverable fuel costs, hedging strategies
2014	Public Service Company of Colorado	CO	14AL-0660E	Colorado Healthcare Electric Coordinating Council	Return on equity, capital structure
2015	WEC Acquisition of Integrys	WI	9400-YO-100	Staff of Wisconsin Public Service Commission	Acquistion analysis
2015	Dominion Virginia Power	VA	PUE-2015-00027	Federal Executive Agencies	Return on equity
2015	South Carolina Electric & Gas	SC	2015-103-E	South Carolina Energy Users Committee	Return on equity
2015	Western Carolina University	NC	E-35, Sub 45	Western Carolina University	Accounting, cost of service, rate design, ROE, capital structure
2016	Sandpiper Energy	MD	9410	Maryland Office of People's Counsel	Return on equity, capital structure
2016	Washington Gas Light	DC	FC 1137	Washington, DC Office of People's Counsel	Return on equity, capital structure

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
2016	Florida Power & Light	FL	160021-EI	Florida Office of Public Counsel	Capital Structure
2016	Jersey Central Power & Light	NJ	EM15060733	NJ Division of Rate Counsel	Asset valuation
2016	Rockland Electric Company	NJ	ER16050428	NJ Division of Rate Counsel	Rate design
2016	Dominon NC Power	NC	E-22, Sub 532	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2017	Potomac Electric Power	DC	FC 1139	Healthcare Council of the National Capitol Area (HCNCA)	ROE and capital structure
2017	Columbia Gas of Maryland	MD	FC 9447	Maryland Office of People's Counsel	ROE and capital structure
2017	Washington Gas Light	DC	FC 1142	Washington, DC Office of People's Counsel	Merger analysis
2017	Duke Energy Progress	NC	E-2, Sub 1142	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2018	Public Service Electric & Gas	NJ	GR17070776	NJ Division of Rate Counsel	ROE and capital structure

Appendix B

The Post and Courier
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43°
Few Clouds

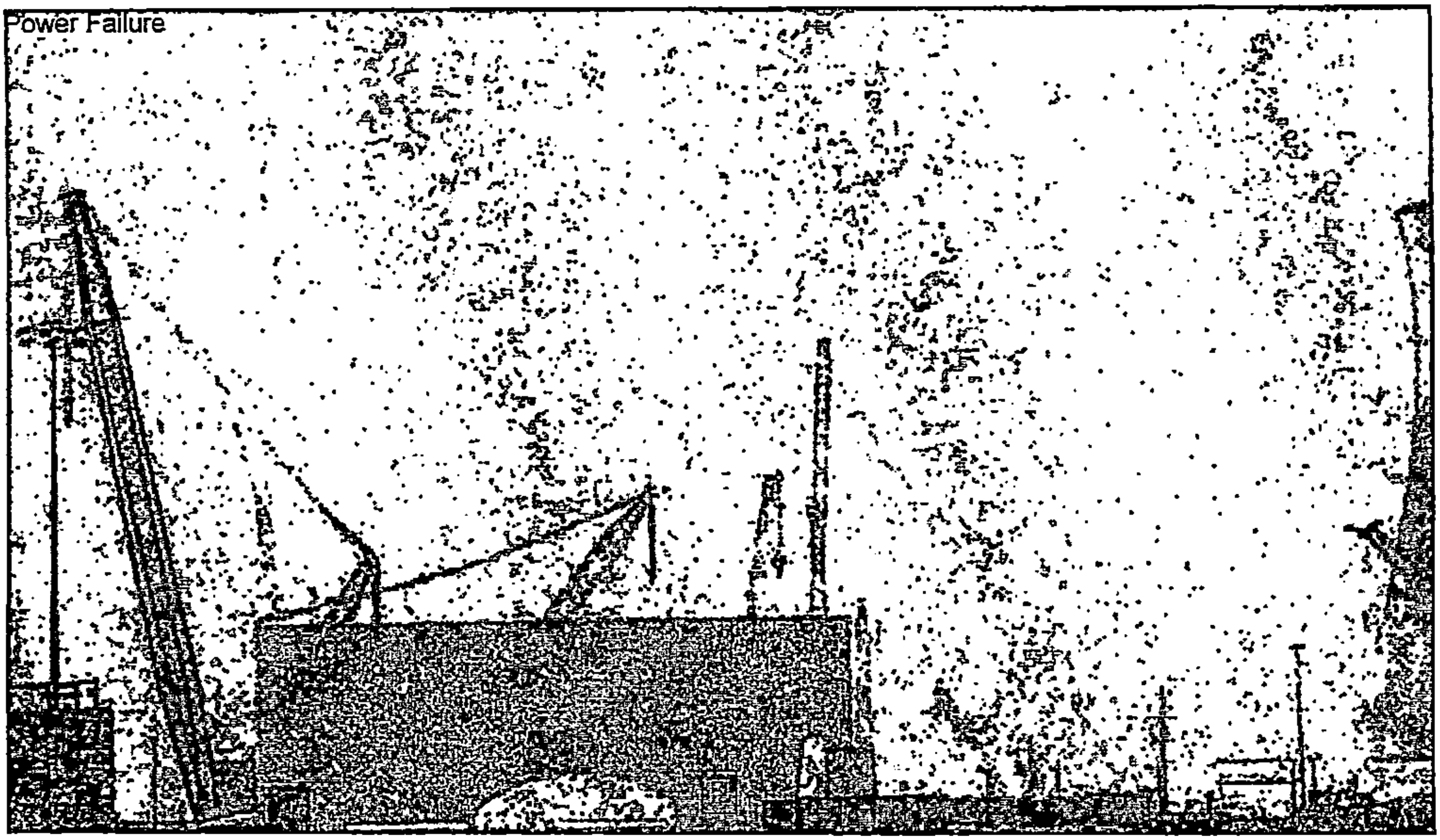
TOP STORY

Power Failure

How utilities across the U.S. changed the rules to make big bets with your money

By Tony Bartelme tbartelme@postandcourier.com Dec 10, 2017 Updated Dec 20, 2017 (12)

24 min to read



Listen to the folks who run some of our biggest electric utilities:

Tom Fanning, chief of Southern Company, in 2016 about its nuclear project in Georgia, which is years behind schedule: "It has gone beautifully. And we're on schedule."

Kevin Marsh, CEO of SCANA, in 2016 about South Carolina's V.C. Summer nuclear project a few months before it collapsed: "We're excited about where we are."

Lewis Hay, CEO of Florida Power & Light, in 2011 about nuclear upgrades that cost twice as much as promised: "Our customers should greatly benefit."

And Fanning again in 2015, this time about his company's clean coal project in Mississippi, which isn't burning coal or cleaning it: "We're on a real winning streak right now.

They should have said "thank you," because money they torched on these and other power plants wasn't theirs.

It was yours.

Over the past decade, state legislatures across the country rewrote rule books for how power companies pay for new power plants, shifting financial risks away from electric companies to you and everyone else.

This rule change ignited a bonfire of risky spending — $40 billion so far on new power plants and upgrades, a Post and Courier investigation found.

Flush with your cash, utilities tried to build plants with unproven technology; they launched projects with unfinished designs and unrealistic budgets; they misled regulators and the public with schedules that promised bogus completion dates; they hid damning reports from investors and the public; they tried to silence critics and whistleblowers.

Then, when delays and cost overruns couldn't be ignored, they asked state regulators to charge you more for their failures.

And what happened to these high-stakes gamblers?

Over the past five years, executive teams of six utilities that bet on these plants won $520 million in salaries, bonuses and other personal compensation, the newspaper found.

For this story, a Post and Courier team of reporters interviewed more than 50 industry experts, utility and construction insiders, whistleblowers and others, as well as lawmakers from states that opened the doors to these risk-shifting laws. Reporters pored through tens of thousands of pages of reports, government filings and other documents.

The result is a tale about power — political and electric. It's about how an industry helped change rules so it could make big bets with your money.

These bets include the now well-documented boondoggle in South Carolina — the V.C. Summer nuclear expansion — $9 billion sunk into two abandoned reactors that may never produce enough juice to run a nightlight.

But they also involve bets on clean coal plants in Mississippi and Indiana.

And nuclear reactors in Georgia.

And projects in Florida and North Carolina that never got off the ground but still cost customers billions of dollars.

These rule changes largely flew under the public's radar as industry insiders worked elbow-to-elbow with lawmakers to craft laws with obscure acronyms and benign language such as "advanced cost recovery."

But the results are as plain as the extra money you pay on your power bill, the fewer dollars you have for groceries.

They are as real as the tuition increases at Mississippi universities because of higher power bills.

As painful as the money schools in Georgia forgo for teachers and lesson plans.

The story could begin in many ways. So why not start with a woman in Mississippi who was about to grab her shotgun.

'A coal plant is coming'

Barbara Correro is a feisty woman, small in stature with a rebellious streak. She says "yes, ma'am" instead of "yes, sir" when she agrees with a man. A retired nurse, she lives in Kemper County, Mississippi, which is on the border of Alabama. It's one of the poorest counties in the country with about a third of its 10,000 residents living in poverty. Its population has shrunk by 100 people a year over the past decade — despite all the money that was spent a short drive from Correro's property.

Barbara Correro lives near the Kemper Energy Facility in Kemper County, Mississippi. Provided

Provided

Correro's home sits hidden in piney woods near cotton fields and rolling hills that also hide deposits of lignite, a form of coal. Longtime residents here talk about how people used to cut off chunks of lignite along river banks to supplement firewood in the winter. It's sometimes called "brown coal" or "wet coal" because it usually contains large amounts of water. This moisture makes it less efficient to burn in traditional coal plants. Yet, in the mid-2000s, Correro and her neighbors heard a rumor: "A coal plant is coming."

Those rumors hit home one day when a tanker truck showed up near her driveway. The crew told her they were doing tests for the coal plant. Across from her gate was a pond that she said "was 150 percent on my land." Without permission, the crew sucked water from her pond into the tanker trucks.

"That's when I told them they have two hours to get out of there before I shoot that pump."

They moved. "The tank truck? That was about intimidation," she said.

More trouble was ahead. A holding company bought thousands of acres around her house. Properties were sold, pitting neighbors who needed money against those who wanted to stay.

She remembers a community meeting not far from her home. An official with Mississippi Power said, "We want you to see the faces of the people you will be working with," according to a story then in the Kemper County Messenger. Other officials told residents they would be fairly compensated for any land that was mined, but they would have to move.

"They were so arrogant," Correro said. "They were basically telling us that they would close roads, buy land, do what they wanted."

Behind the scenes, Southern Company and Mississippi politicians had orchestrated a complex but potentially lucrative trade — courtesy of federal taxpayers. Southern Company and a Florida utility had been working on a government-subsidized "clean coal" project near Orlando, one that had fizzled. A Department of Energy memo acknowledged the plant was not "technically or economically feasible" in Florida.

Enter former Southern Company lobbyist Haley Barbour, the avuncular Republican Party stalwart. Elected governor of Mississippi in 2004, Barbour and Southern Company persuaded the Department of Energy to move the foundering project and its $270 million in federal grants from Orlando to Kemper County — and then make it much bigger, more expensive and pin costs mostly on federal taxpayers and Mississippi customers.

The more Barbara Correro learned about the plant, the more she thought it was wrong for Kemper County. In her mind, Southern Company and its subsidiary, Mississippi Power, were gambling with their money and land.

When ground broke in 2010, "I was heartbroken," she said.

Risky as it was, the Kemper County project was part of a much larger gamble — a spending frenzy on new power plants.

The spree's origins are mostly in the mid-2000s, but it's also helpful to step farther back in time, to the late 1800s and Thomas Edison, who didn't invent the light bulb.

Monopolies are born

Hard to believe, given the tidy stories about Edison that schools have taught, but historians have long known Edison's contributions were more nuanced. Other inventors, including Britain's Joseph Swan, created incandescent bulbs years before Edison filed his patents. Yet Edison did something more important.

He invented longer-lasting bulbs. Then he developed ways to connect groups of bulbs to generators, a grid that could supply electricity to large numbers of customers. In 1882, Edison built the first electric utility on Pearl Street in New York City, igniting a movement to light the world with electricity instead of flames.

A surge of new electricity entrepreneurs in the early 1900s wired one city after another. But many of these young power barons realized that large and duplicative transmission systems were expensive and inefficient. They bought competitors, then urged state governments to regulate their businesses as "natural monopolies."

It seemed like a fair deal: In exchange for being regulated, utilities solidified their monopoly status and baked in guaranteed rates of return for their investors. Meantime, state public service commissions would make sure utilities charged customers reasonable rates.

But today, the heirs of Edison's original Pearl Street grid have become a $220 billion industry, one that has shrunk to a patchwork of powerful public and private fiefdoms.

Public service commissioners, some elected, some appointed by lawmakers, are still responsible for balancing needs of consumers and utilities. Yet, when it comes to weapons of influence, consumers increasingly find themselves outgunned.

During the past decade, power companies and their allies spent $1.4 billion on federal lobbying, campaign records show. They gave $112 million to federal candidates. They shoveled millions more into statewide races. They poured money into campaigns of public service commissioners in Georgia, Mississippi and Alabama — states that elect regulators. Relationships got cozy.

In Georgia, electric industry lobbyists ply commissioners with expensive meals and send them smoked hams for Christmas, an Atlanta Journal-Constitution investigation found. Between 2014 and 2016, Georgia Power bought commission staffers and contractors more than 200 meals and refreshments, a review by the Energy and Policy Institute found. Most were small meals, though earlier this year, Georgia Power lobbyists spent $7,700 to feed commissioners and staff at a single dinner at the Lake Oconee Ritz-Carlton. In 2012, a commissioner asked a lobbyist to pave the way for his granddaughter to sing the national anthem at an Atlanta Braves game.

In South Carolina, the state Legislative Audit Council faulted public service commissioners for getting too close with lobbyists and other industry representatives. In response, lawmakers created the Office of Regulatory Staff to defend the "public interest" in cases before the Public Service Commission. But the law defines "public interest" as a balancing act between the needs of customers and "economic development" forces. And this reform push did away with the state's consumer advocate, who had successfully fought rate increases in the past. Critics said the law tilted the balance against customers at a critical moment.

In the mid-2000s, power companies across the South, including SCANA, NextEra, Duke Energy and Southern Company, had their robust lobbying machines running at full throttle.

An energy gold rush had begun.

The rule writers

The lobby of the South Carolina Statehouse is a pleasant place to visit. The room's 19th century treatment is reminiscent of Edison's time, with stained glass windows, leather couches, mahogany doors and a paint palate of warm browns. When in session, lobbyists and lawmakers huddle around a life-size statue of John C. Calhoun. School groups weave through these conversations on their way to the chambers. John M. Bryan, former professor of art history at the University of South Carolina, once said the lobby's openness "symbolizes accessibility of government to all people."

But in the spring of 2007, operatives for South Carolina's utilities often met behind closed doors, away from the public din of the Statehouse lobby. One meeting took place in a conference room of Haynsworth Sinkler Boyd, a politically influential law firm with an office then next to the Capitol grounds. Belton Zeigler, one of the firm's lawyers at the time and former general counsel for SCANA, was the host. The subject: A new bill called the Base Load Review Act.

Though he wasn't a lawmaker, Zeigler had helped draft the bill. Its first words were: "An act to protect South Carolina ratepayers."

It was a dramatic break from the past.

Power companies in South Carolina had raised money for new plants by selling bonds and tapping other financial markets. Then, when the plants came online, they incorporated these borrowing costs in rates.

Put another way, customers paid for new plants when they received something for their money — electricity.

It was like buying groceries: You pay the store and get your food.

But traditional lenders were leery about backing nuclear plants given the financial failures of so many reactor plans in the 1980s.

So power companies came up with another source of money — yours.

And they had just the tool to pry it loose.

Legislative lightning

This tool went by several tongue-twisting acronyms and terms: CWIP, short for "construction work in progress"; AFUDC, short for "allowance for use of funds during construction"; and "advanced cost recovery."

But they all did the same thing — shift risks of construction projects from power companies to their customers.

Instead of billing you when new plants went online, power companies did it as they licensed, designed and built them.

This tool suddenly made you an investor in a future power plant. It was like paying a grocer as it builds its store — with the hope that groceries might be a little cheaper when it opens.

Water and sewer utilities routinely use cost recovery and CWIP laws for small or predictable upgrades, such as pipelines.

But using these pay-as-you-go tools for nuclear reactors was another matter.

Supporters said new CWIP laws would generate billions of new dollars and help ease rate shock when plants came online. A handful of critics predicted they would encourage big bets on dicey projects.

"There are checks and balances when you pay something out of your pocket," said Louie Miller, a lobbyist for the Sierra Club in Mississippi. "When it's other people's money, it's easier to take a risk."

But power companies couldn't collect any of this new money without help from elected officials.

Which in South Carolina and across the South seemed inevitable.

'Trust the people in authority'

In North Carolina, the race for nuclear never took off

Bobby Harrell, then-Speaker of the House, said power companies made a persuasive case: They needed more generating plants to keep up with future demand.

"When you're in the General Assembly, you have a need to be able to trust the people in authority," Harrell, a Republican, said in a recent interview.

Glenn McConnell, then-Senate President Pro Tempore and another key supporter, warned: "We don't need blackouts like in Baghdad here in South Carolina."

Tommy Moore, a Democrat from Aiken and a champion of the bill in the Senate, said a move toward nuclear energy made sense at the time: Costs of coal plants were rising and natural gas prices were still high. "I don't remember anyone breathing any caution."

The spring 2007 meeting with Belton Zeigler, the former South Carolina Electric & Gas lawyer, had been billed as a chance for manufacturers to weigh in. But some attendees left feeling the bill was a done deal.

As industry representatives suggested tweaks, Zeigler cast most of them aside.

"I can remember when we hit a brick wall Belton would say 'I hear you,' " said Scott Elliott, an attorney for the South Carolina Energy Users Committee, a group that represents industrial customers. "I hear you" really meant the language already was etched in stone, Elliott said. Zeigler declined to comment for this story.

By then, the bill was already filed in the House and Senate, and power companies had done their legwork. They had pumped more than $510,000 into lawmakers' campaigns before the session. More than two-thirds of the lawmakers signed on as sponsors.

Greased by campaign cash, the bill sped through the Legislature at the political equivalent of lightning.

"When you see the title, nothing about it seems controversial," said Rep. Robert Brown, D-Hollywood, one of the law's few opponents. "Some people probably went along and voted for it without really knowing what they were voting on."

The Senate passed it on a voice vote, wiping away fingerprints of those who supported or opposed it.

Chip Campsen, a Republican from the Isle of Palms, was one of the few senators who voiced a no. He'd studied the bill's language and saw it shifted risks from utility shareholders to customers, which seemed wrong to him.

"There are very few votes over the years that bother you, but this one ... I could not believe we did that."

Legislators once spent five months arguing about whether to name the right whale or the bottlenose dolphin the state marine mammal. But it took just seven days to move the Base Load Review Act from a Senate subcommittee directly to a final vote on the House Floor. Only 6 of 104 House lawmakers opposed it. It contained no penalties if utilities messed up their projects. Or spending caps.

When the bill went to then-Gov. Mark Sanford for his approval, Sanford declined to sign or veto it, which meant it automatically became law. Tom Davis, Sanford's chief of staff at the time and now a Republican senator in Beaufort, said it was a "foregone conclusion this was going to be law" no matter what Sanford did.

"This bill was entirely industry driven — in the drafting of it, in the advocacy of it, in terms of putting pressure on legislators," Davis said. "It was probably the clearest case I could ever see of a special interest using all of its power and leverage to get something passed."

States of influence

At least 11 states passed similar pay-as-you-build laws during the 2000s. Florida utilities lobbied for a nuclear "cost-recovery" bill that left Susan Bucher, a Democrat in the Florida House, wondering: "You're going to make my senior citizens pay for something they will never see?"

She stood on the House Floor to voice her opposition: "What happens if they don't complete the plant?"

The Legislature answered with a vote of 158 to 1.

It was a heady time for power companies. In a short period, state elected officials across the country, and especially in the fast-growing South, had created new sources of money they didn't have before. With an all-you-can-eat buffet of customer cash and taxpayer-funded subsidies, power companies proposed one expensive project after another. Early estimates called for more than $80 billion worth of new power plants and upgrades in the South alone, a Post and Courier analysis showed.

Industry cheerleaders said these plants could transform the South into an electricity powerhouse, one primed to take advantage of future laws that penalized generators for releasing large volumes of carbon dioxide, the primary cause of global warming.

Mississippi lawmakers went all in, passing a law that encouraged both nuclear and "clean coal" plants, including the project in Kemper County — a "home run for Mississippi and the nation," Gov. Haley Barbour wrote the Secretary of Energy in 2010, shortly before the groundbreaking.

The Kemper County plan was ambitious. Massive diggers would strip mine lignite from the hills and fields around the plant. The lignite would then be converted into synthetic gas. This gas would be burned to spin turbines that generated 582 megawatts of electricity, enough to power 430,000 homes. Two-thirds of the carbon dioxide emissions would then be diverted from the plant's stacks, captured and sold to oil extraction companies. Southern Company said the plant's technology could be replicated and sold across the world.

Kemper's potential was one of the reasons Brett Wingo was eager to work on it. His grandfather had been a coal miner in northern Alabama. Wingo did engineering work on the gasification island, the portion that turned lignite into gas.

"I wanted to be part of a solution that saved the industry."

He never thought he'd end up calling the project a fraud.

Construction of a whistleblower

Wingo is a tall man with a low-pitched Alabama twang and a restless energy about him. In a recent interview, his right fist was sore from pounding it during a rare loss by the University of Alabama's football team. He lives near Birmingham and commuted every week to Kemper County, a two-hour drive. Since he worked on the plant's original designs, he knew its anatomy like a surgeon.

"It's like a huge petrochemical plant with giant flares and columns. You had to do the engineering right. There was enough ammonia to kill everyone on the site."

He won internal awards for his work and was placed in programs to nurture promising managers. He thought the gasification and carbon sequestration technology was sound, but by 2013, he knew the project was in trouble. Already, Mississippi Power had admitted to state regulators that it had hidden $366 million in cost overruns.

Wingo suspected it was way behind schedule, which could add dramatically to its overall costs. Two important deadlines were fast approaching.

The first was May 14, 2014. If the plant wasn't online then, Southern Company would lose $133 million in federal tax credits — money the company and its shareholders would have to eat instead of customers.

The second was Dec. 31, 2014. Miss that one, and Southern shareholders would swallow another $150 million in federal tax breaks.

Wingo told his superiors that they'd likely never make those deadlines.

But they seemed to ignore his warnings. In public meetings with Wall Street analysts, Southern executives painted pictures of "tremendous progress." They were on track to make those 2014 deadlines — and keep those federal tax breaks.

Then, during the summer of 2013, Wingo was told to build a new plan for the plant's start-up, a chance to dig deep into the inner workings of the project's overall schedule.

He would soon learn whether his suspicions about the deadlines were right.

'Impossible to make it'

Construction schedules for nuclear, coal, bridge and other major projects are typically done using powerful software programs such as Oracle's Primavera P6 and Microsoft's Project.

Much more complex than spreadsheets, these programs allow you to identify hundreds of thousands of tasks: inspections, supply purchases, man-hours, productivity rates and costs. Diligent managers then arrange these variables and many other tasks in logical sequences. For instance, to make reinforced concrete, a schedule might call for installation of rebar, inspections and then the pouring of concrete.

When the data is fully loaded, the program spits out bar charts, cost scenarios — and dates when tasks should be finished. It also gives you a final completion date, along with probabilities this date will be met.

Wingo and his colleagues worked for five weeks to craft their new schedule. They punched in data for more than 5,000 tasks. When they were finished, he sent his findings up the corporate ladder.

"I told them that it was impossible to make that May 1, 2014, deadline, and that it probably wouldn't be finished well into 2015 or later."

+16

Tom Fanning, president and CEO of the Southern Company, speaks at an energy summit in Jackson, Miss. in 2012. File/Rogelio V. Solis/AP

Rogelio V Solis

But time and again, Fanning and other Southern Company executives reassured Wall Street analysts: Those deadlines were still good.

By early 2014, it was obvious that work at Kemper would continue far past its first deadline and lose the first batch of tax credits. Southern Company executives blamed the delay in part on bad weather. But the second deadline for those tax breaks would be met, Fanning said April 30, 2014. "Well, except for the unknown unknowns," he added. "So what happens if, heaven forbid, there's a tornado that comes across the site? Or what happens if there's a major hurricane? Or what happens if, as we integrate the system, it's just more complex, and we are not able to track it effectively or something?"

Wingo was bewildered by the contrast between the positive public story Southern executives told and the chaos at the work site. He said the company put pressure on engineers to speed up designs, sacrificing safety to meet the deadlines. He worried that workers would get hurt.

In early 2014, he wrote an email to a high-level executive: "I've reached a personal tipping point and feel a duty to act."

Other bets, other losses

As Brett Wingo pondered what to do next at Kemper, other pay-as-you-build plans went south.

Like Southern Company, Duke Energy had its own clean coal project. Duke's was in Edwardsport, Ind., and it earned a reputation for generating scandals as much as electricity. One involved a lawyer for the state's utility commission: He negotiated a job with Duke as the company sought hundreds of millions of dollars from customers because of construction overruns. The state's Supreme Court later fined and reprimanded the lawyer.

The Edwardsport project itself was a money pit. Its original price tag was $1.9 billion plus millions more in financing costs. But delays and overruns eventually pushed the tab for customers to at least $3.7 billion so far. In the end, Duke nixed the carbon sequestration component. For their money, customers got a plant that burns synthetic gas, didn't clean CO_2 and cost nearly twice as much to operate as neighboring utility plants.

+16

Duke Energy's Crystal River nuclear power plant in Citrus County, Fla., on June 27, 2013. File/Phil Sandlin/AP

Phil Sandlin

In western Florida, Progress Energy bungled repair and upgrade work on a 30-year-old reactor near Crystal River. When Duke Energy merged with Progress in 2012, Duke decided to shut down the reactor altogether. By then, electric customers had paid $381 million for the upgrade. They will shell out another $1.3 billion for the next two decades to decommission the plant — for no electricity.

Progress Energy also pushed for two new reactors in Levy County north of Tampa, buying land and signing a contract with Westinghouse Electric. But in 2013, after the Duke merger, Florida lawmakers tweaked their cost recovery law. Moving forward, lawmakers wanted utilities to first prove their plants were feasible and made economic sense. This not-so-high bar was enough to kill the project. It created "increased uncertainty in cost recovery," Duke Energy said then. In other words, Florida lawmakers made it slightly more difficult to charge customers for new reactors.

Duke's customers still paid about $871 million for land and other contractual obligations — for no electricity.

+16

The Turkey Point nuclear plant is south of Miami Florida Power and Light spent billions of dollars to expand its existing reactors there and another up the coast. The company has also pushed plants to build a pair of new reactors at the site in a project that would mirror South Carolina's V.C Summer plant. File/Lynne Sladky/AP

Lynne Sladky

Farther south near Miami, Florida Power & Light is weighing a decision to build two Westinghouse reactors at its existing Turkey Point nuclear station. Though its plans are in limbo, Florida Power & Light charged customers anyway — about $275 million so far. The power company also spent $3.4 billion on upgrades to its other nuclear reactors, nearly twice the original estimates.

Taken together, the Florida pay-as-you-go projects cost customers $6 billion.

Meantime, Southern Company and SCANA burned through billions of customer dollars — more than $9 billion at V.C. Summer in Fairfield County, and $12 billion at Vogtle, south of Augusta.

And as in Kemper County, Mississippi, the Georgia and South Carolina projects had construction schedule issues of their own.

Dishonest schedule

Their contractor, Westinghouse Electric, had touted its AP1000 reactor as an off-the-shelf design. But as construction began, Westinghouse still needed thousands of detailed engineering blueprints and drawings. To get this work done, the company used unlicensed engineers, a potentially criminal shortcut, a Post and Courier investigation revealed earlier this year.

They'd been warned about this practice early on. In 2011, a Westinghouse official circulated a confidential analysis to the company's leadership. This report predicted the company would lose hundreds of millions of dollars because of its questionable engineering practices and other strategic blunders. But his warnings apparently fell on deaf ears.

"This thing was rotten from the get-go" one engineer from V.C. Summer said. "They were going to do it their way, and they weren't going to listen to anyone."

Questionable engineering wasn't the only problem at V.C. Summer and Vogtle. Fabrication of the plants' key components also went badly, especially at a subcontractor's factory in Louisiana.

Chris Hartz, a quality assurance manager for one of Westinghouse's subcontractors, said a team inspected the Lake Charles, La., plant in 2010 and found serious problems with welds and paperwork. It was clear that the new facility and its employees weren't prepared to manufacture components that met tighter nuclear safety rules, he said. His team had the power to shut down the site, and it did.

But when he informed a senior executive about the team's decision, the man threw a letter opener at his head. Hartz said it missed him by a few inches and crashed into a plate glass window.

Chaos at the Louisiana factory added more uncertainty to schedules in South Carolina and Georgia. But you'd hardly know if you listened to SCANA and Southern Company executives.

Stephen Byrne, executive vice president of SCANA, told Wall Street analysts in late 2012 that V.C. Summer's "construction is progressing well." Its first reactor was scheduled to go online as planned in March 2017. He added then that SCANA had already sought and won five rate increases under the state's Base Load Review Act.

"We continue to be pleased that the mechanism is working as designed."

In reality, both the Vogtle and V.C. Summer projects lacked honest schedules, ones that fully incorporated all the tasks, costs and other variables from beginning to end.

In 2012, a construction expert hired by Georgia regulators sounded an early alarm: The absence of an honest schedule made it difficult for regulators and the public to know when the project would be done and how much it truly would cost.

He issued the same warnings year after year as the overruns grew.

But Georgia regulators approved one rate increase after another.

The same thing happened 120 miles away at the V.C. Summer work site.

In 2015, Bechtel, a consultant SCANA hired to analyze the project, found 50 cases in which Westinghouse's schedule had bogus completion dates. Overall, the schedule didn't reflect "actual project circumstances," the Bechtel report said.

In 2016, a construction monitor hired by South Carolina regulators said that Westinghouse managed the mammoth V.C. Summer nuclear expansion on what amounted to three- to six-month "lookahead" schedules.

Behind the scenes, SCANA and Santee Cooper executives wrestled with the project's mounting financial and worksite issues. They kept the Bechtel findings secret from regulators until this year when the governor ordered it released. And they spun a different, much rosier tale in public.

Chairman and Chief Executive Officer SCANA Corporation Kevin Marsh talks to the press at the construction site of the new reactors at the V.C. Summer Nuclear Power Station in Jenkinsville on Wednesday, September 21, 2016. File/Grace Beahm/Staff

Buy Now

By Grace Beahm Alford gbeahm@postandcourier com

In September 2016, Kevin Marsh told reporters: "People ask, 'If you could do it again, would you make the same decision?' Absolutely, I would make the same decision. I feel as strongly today — probably even stronger today than I did back in 2008 — that this is the solution for us, for a clean energy future."

And V.C. Summer's hidden problems didn't stop SCANA and Santee Cooper from raising rates.

Since 2009, SCE&G has asked for nine rate hikes to pay for its nuclear plant.

Each time, our state Public Service Commission gave them nearly everything they asked for.

Real costs, real pain

For roughly 717,000 SCE&G customers, those rate increases come to 18 cents for every dollar on their monthly bills. It adds up to about $37 million every month, or nearly $500 million a year.

That's about $40,000 a year in extra utility expenses for the Charleston Animal Society, enough to save 107 dogs and cats, the group says.

It's about $1.2 million extra for the city of Charleston, enough to pay starting salaries for 26 police officers, city figures show.

It's about $43,000 a month more on Roper Hospital's power bill, money the hospital could use to expand its telehealth network and other work, said Bret Johnson, Roper's chief financial officer.

It's money for zero electricity.

And that's just in South Carolina.

As much as $853 million will end up on the backs of Mississippi Power's 187,500 customers because of the Kemper project.

That's more than $4,500 per customer in a state where 1 in 5 residents have difficulty getting enough food because they're short of money. After a rate increase in 2014, University of Southern Mississippi faced as much as a $1 million jump in its bill and had to raise tuition $236 per student.

Barbara Correro, the early Kemper County foe, said, "I know I'm hurting because of higher electric bills." And she's heard that some elderly residents can't afford to turn on their air conditioners in the summer.

While we forked over money for risky projects that didn't produce power or cost much more than originally advertised, power company executives saw their wallets grow fatter.

+16

NextEra CEO James Robo.

Top executive teams of five Southern utilities collectively earned an average of $104 million a year between 2012 and 2016, or a total of $520 million.

NextEra's CEO, James Robo, earned the most, a cool $16.7 million in 2016. Tom Fanning, Southern Company's CEO, earned a tad less at about $16 million.

They earned significantly more than SCANA's CEO, Kevin Marsh, who made $6.1 million that year. Lonnie Carter, CEO of Santee Cooper, which is owned by the state, made the least at $540,000.

Marsh and Carter have since retired amid the V.C. Summer collapse. Other CEOs have survived, including Fanning, though his leadership stock took a hit last week. Analysts for Georgia's Public Service Commission made a startling recommendation: the Vogtle expansion should be canceled. Given the delays and mismanagement, the project no longer made economic sense for Georgia Power customers, they said.

Former Santee Cooper CEO Lonnie Carter and outgoing SCANA chief Kevin Marsh during a media tour of the now-abandoned V C Summer Nuclear Station last September. File/Grace Beahm Alford/Staff

By Grace Beahm Alford gbeahm@postandcourier com

Fanning declined to comment for this story.

But in the fall, he spoke at an energy summit in Chicago hosted by a women's business group. Participants tweeted some of his comments about leading a large power company.

In one, Fanning was reported to have said: "What you really want as you rise in an organization is the truth."

Back in Kemper County

So did Brett Wingo.

Suspecting something wrong with the Kemper project's overall schedule, he analyzed parts that other managers had built. That's when he discovered that someone had overridden the "logic ties" — sequences of tasks that were supposed to go in order but didn't.

One example: The schedule had the plant's two gasifiers coming online simultaneously. But he and his colleagues had designed them to fire one after each other, like a rocket booster firing stages. "This had the stages going off at the same time. It was impossible," he said.

The broken logic ties made progress look better on paper than it was at the work site. Wingo feared the truth of the project's problems weren't bubbling up to the executive suites. He worried that Fanning might be unintentionally violating federal securities laws by misleading investors because of a sham schedule. He reported his concerns in an email to an executive at Mississippi Power. But the executive berated him for putting his report in writing because lawyers could dig it up in a lawsuit.

On his way home one day in March 2014 to Birmingham, Wingo decided to call Fanning directly.

He remembers pulling to the side of the road, near a cow pasture. He dialed Fanning's number and was surprised when he picked up on the second ring.

He told Fanning what he'd found in the schedule. He warned him against signing any financial reports to the Securities Exchange Commission that claimed the plant would be done by the end of 2014.

He said Fanning thanked him. "He told me I'd done the right thing." Wingo drove home, relieved.

But within weeks, project managers excluded him from meetings. They left him off emails. Two colleagues warned he was "digging a hole" for himself. He was ordered to turn over his scheduling duties, a demotion. Wingo began to secretly record calls with co-workers to protect himself.

Wingo eventually filed a job retaliation complaint with the Occupational Safety and Health Administration and another with the SEC alleging the company broke securities laws by misrepresenting the plant's schedule. A Southern Company lawyer allegedly told him his career was over.

At one point, a company lawyer offered Wingo nearly $1 million for his silence, he said. The lawyer "pushed it across the table to me in his offices, gave me 24 hours to sign it and said if I ever disclosed this, he would deny it." Wingo refused the offer. Southern obtained a temporary restraining order to keep him quiet, which was later dropped. "I felt like the company was intent on having their way with me, no matter my protests."

Earlier this year, OSHA sided with Wingo, saying his employer had an "irresponsible disregard to the whistleblower protections enforced by OSHA."

Fanning has described his phone call with Wingo as "a nice conversation," said Schuyler Baehman, a Southern Company spokesman. After the call, Fanning turned the matter over to the company's general counsel and chief compliance officer. The company investigated Wingo's concerns and found they were "unsubstantiated and not otherwise supported by the facts," Baehman said.

Southern fired Wingo in 2016, and he's filed a federal lawsuit alleging that Southern went after him for trying to tell the truth.

"I never thought I'd be a whistleblower."

His predictions about the project's schedule came true. Southern missed its deadlines in 2014, and it's still not done. Costs ballooned from $2.4 billion to more than $7.5 billion so far. It won't turn Kemper County's lignite into gas; that plan was shelved because it didn't make economic sense. And it doesn't collect carbon dioxide. That part also was nixed.

One part of the plant does work — the section that burns natural gas.

A new natural gas plant typically costs about $700 million. So at $7.5 billion and counting, industry analysts say Kemper is on its way to becoming the most expensive natural gas plant in the world — smack in the middle of one of the poorest counties in the country.

Lessons learned?

Failure can be a gift when lessons are learned and used to prevent future ones. And the failures of so many pay-as-you go projects across the South offer plenty of teachable moments.

Among them: South Carolina's V.C. Summer fiasco wasn't an isolated case. When Brett Wingo sees questions raised about scheduling and overruns at the Vogtle and V.C. Summer nuclear projects, his mind flashes back to what happened at Kemper in Mississippi.

"I'm constantly seeing similarities," he said.

This industry-wide pattern presents a high-stakes cautionary tale, especially as South Carolina lawmakers talk about possible sales of SCANA and Santee Cooper.

NextEra, Duke and Southern have all been mentioned as suitors. All used pay-as-you-go tools to shift costs of risky projects to customers. And their executive teams took home even more money than executives at SCANA and Santee Cooper.

Meantime, nearly all the laws that launched the gambling spree remain on the books, including South Carolina with its Base Load Review Act and opening proclamation: "An act to protect South Carolina ratepayers ..."

Andrew Brown, Thad Moore, Glenn Smith, Seanna Adcox and John McDermott contributed to this report.

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