BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1300

In the Matter of		
Application of Duke Energy Progress,	)	**TESTIMONY OF**
LLC for Adjustment of Rates and	)	**DUSTIN R. METZ**
Charges Applicable to Electric Service	)	**PUBLIC STAFF –**
in North Carolina and Performance	)	**NORTH CAROLINA**
Based Regulation	)	**UTILITIES COMMISSION**

March 27, 2023

Table of Contents

Introduction

Q. Please state your name, business address, and current position.

A. My name is Dustin R. Metz. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Energy Division of the Public Staff – North Carolina Utilities Commission.

Q. Briefly state your qualifications and duties.

A. My qualifications and duties are included in Appendix A.

Q. What is the mission of the North Carolina Public Staff?

A. The Public Staff represents the concerns of the using and consuming public in all public utility matters that come before the North Carolina Utilities Commission. As defined by N. C. Gen. Stat. § 62-15(d), the Public Staff has a statutory duty and responsibility to review, investigate, and make appropriate recommendations to the Commission with respect to the following utility matters: (1) retail rates charged, service furnished, and complaints filed, regardless of retail customer class; (2) applications for certificates of public convenience and necessity; (3) transfers of franchises, mergers, consolidations, and combinations of public utilities; and (4) contracts of public utilities with affiliates or subsidiaries. The Public Staff is also responsible for appearing before State and federal courts and agencies in matters affecting public utility service.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to set forth the Public Staff's findings and recommendations resulting from our examination of the Application of Duke Energy Progress, LLC (DEP or the Company) in Docket No. E-2, Sub 1300, filed on October 6, 2022, (Application).

Q. What was the scope of your investigation regarding the Company's Application in this proceeding?

A. My investigation covered two main components, a review of certain Base Case[1] costs sought for cost recovery in the current rate case and certain elements of proposed capital projects in the Multi-Year Rate Plan (MYRP) that are part of the Company's Performance Based Regulation (PBR) Application. For purposes of my initial testimony in this case, I reviewed historic costs associated with projects placed in service for the period June 2020 through November 2022. My investigation incorporated multiple site visits to the Company's fleet of generating stations and an operations center to review certain projects, including projects that were complete and others that were under construction. In addition, I participated in numerous meetings, both virtual and in person, with Company staff.

Q. How is your testimony organized?

A. My testimony is organized in four main parts:

[1] The Base Case is the historical spend that DEP is seeking to recover under N.C.G.S. § 62-133.

I. Summary
II. Base Case Recommendations and Findings
III. Fossil Generation Trends
IV. MYRP Rate Case Recommendations and Findings

Q. Are you providing any exhibits with your testimony?

A. Yes. I am including two exhibits, described below:

Exhibit 1. Non-Confidential DEP Data Responses to Public Staff Data Requests No. 90, 137, 138, 155, and 232

Exhibit 2. Confidential DEP Data Response to Public Staff Data Request No. 42

I. Summary

Q. Please identify the areas you investigated.

A. In addition to serving as the Public Staff's technical director for this proceeding, I specifically investigated, supervised, and worked with other members of the Public Staff on review of the following:

- Fossil generating fleet performance and reliability.
- Base Case spend for generation, transmission, and distribution, including:
  - Capital additions;
  - Materials and supplies (M&S) inventory;

- E-1, Item 10, NC-2100 - Adjustment to levelize nuclear refueling outage costs;
- E-1, Item 10, NC-2120 - Adjustment to end of life nuclear costs; and
- E-1, Item 10, NC-2160 - Adjustment to coal test year O&M.[2]

○ Staffing levels for specific work groups.

○ Transmission plant cost allocation.

○ Prospective components of the Company's MYRP capital plant additions for generation, transmission, and distribution, including the following:

- Project need;
- Timing of implementation and completion;
- Cost estimates; and
- Staffing.

○ Supervision of Public Staff consultant GDS Associates, Inc. (GDS), in its review of the Company's proposed MYRP transmission additions, including:

- Power flow analysis; and
- Project need.

[2] Pro-forma NC-2160 was filed in the Company's February update.

Q. Please summarize your recommendations resulting from your investigation.

A. Based on my investigation, I recommend the following adjustments:

- Shift the costs of Project Walter, DEP's new Energy Control Center, from the Base Case to Rate Year 1 of the MYRP.
- Remove the capital costs of Project Florence, DEP's new transmission service building.
- Remove costs associated with unusable inventory (M&S Inventory).
- Modify proposed O&M for coal-fired generating stations (NC-2160).
- Modify inventory salvage value (NC-2120).
- Adjust transmission cost allocation.
- Adjust MYRP project contingencies.
- Adjust select MYRP project efficiencies.
- Remove specific MYRP transmission projects (based on GDS's findings).

In addition to those specific recommended adjustments, I address the following concerns:

- Declining performance trends of the Company's fossil generating fleet, including decreased unit availability, elevated outage rates, and decreased staffing.
- Uncertainties around staffing, execution, and risk management of elements of the Company's proposed MYRP projects.

II. Base Case Review and Findings

Q. What adjustments are you proposing for capital projects closed to plant?

A. I have two recommendations. The first adjustment removes the costs of a new transmission building located in Florence, South Carolina (Project Florence). The second adjustment transfers the cost of the new Duke Energy Progress Energy Control Center (Project Walter) from the historic test period to Rate Year 1 of the MYRP.

A. Project Florence

Q. What is Project Florence?

A. Project Florence is a new transmission services building. The Company has distributed operations centers throughout its service territory to support multiple utility functions, including a pre-existing transmission operations center to support maintenance and construction activities for its Florence, South Carolina area, also known as the Carolinas East Southern Region. Prior to Project Florence, transmission services in this area were served from two buildings on the same lot. The Company made an internal business decision to build a new consolidated transmission services building and demolish the two older existing buildings at the pre-existing site (total system cost of ~$14.2M), for which it is seeking cost recovery in this case.

Q. What was the Company's justification for Project Florence?

A. The Company stated:

> "[t]he goal of this project is to consolidate the Construction, Maintenance and Relay crews along with support functions for Transmission into a single facility. The staff is currently located in 3 separate facilities. The optimization and re-design of the existing laydown yard is to increase efficiency and provide better fleet vehicle and trailer parking."[3] [4]

Project Florence began in July 2017, and was placed in service in April 2021. The Company was unable to produce a cost benefit analysis for the project or a list of annual incremental O&M savings in discovery.[5] DEP did, however, provide a Confidential Initial Business Case and other project documentation, stating:[6]

[Begin Confidential]

[redacted]

---

[3] *See* Company response to PS DR 42, "DEP PS DR 42 Attachment".

[4] There were only two buildings, not three. See Company response to PS DR 90-1 and 90-8.

[5] *Id.*

[6] *See* PS DR 43, Confidential Attachment 5 & 8.

[redacted]

[End Confidential]

In addition, the Company provided a Confidential Post Project Debrief Power Point presentation, which contained numerous errors, as well as information that was not relevant to the project.[7]

The two pre-existing buildings, the Construction Building built in 1996 and the Maintenance Building built in 1978, replaced by Project Florence were demolished once Project Florence was operational. The Company replaced the roofs of both pre-existing buildings and made other security enhancements in 2014 at an aggregate capital cost of around $200,000. Staffing levels at the site prior to Project Florence were as follows: (1) 2017- 43 employees, (2) 2019- 56 employees, and (3) 2021- 38 employees, with office space utilization below 60%. The Construction and Maintenance buildings had relatively low and static annual operations and maintenance (O&M) costs of ~$30,000 to $35,000.[8]

---

[7] *See* Company response to PS DR 42, Confidential Attachment 7 and the errors identified in follow up discovery, PS DR 90-10, 18 thru 20. The errors are located on Confidential Attachment 7 page 3, Economics and Benefits Delivery and Change Order Sections.

[8] *See* Company response to PS DR 90-3.

The Company stated that during utilization of the pre-existing buildings and prior to the construction of Project Florence, "crews were able to perform work to maintain the grid, but the space needs were constrained for materials and equipment. Keeping order of things had its difficulties."[9] The Company further indicated that optimization and re-design of the existing laydown yard was to increase efficiency and provide better fleet and vehicle trailer parking. Below are Public Staff questions and the Company's responses regarding the cost and need for the new building.

> ***PS question***: Demonstrate how the existing three-building layout was not effective or efficient and quantify the impacts and lost production on an annual basis.
>
> ***Company answer***: Due to the separation of teams and materials, the time needed to deploy from the center to the work was not effective or efficient. A true cost model to quantify this impact was not performed as part of the business case for the new facility.
>
> ***PS question***: Describe how the existing laydown yard was inefficient and how fleet and trailer parking was a challenge or ineffective.
>
> ***Company answer***: A laydown yard needs proper flow. The original site was not built to suit the size of new vehicles and materials used today. Turning radiuses for vehicles was challenged by the old layout. Due to this, material staging was made more difficult as well. [10]
>
> ***PS Question***: Provide a cost justification and supporting analysis, with all assumptions and variables defined and provided, that demonstrate this capital investment was more cost effective than maintaining/continuing operations of the

[9] *See* Company response to PS DR 90-4 & 90-6.

[10] *See* Company response to PS DR 90-6.

> three existing locations and/or continuing the lease arrangement.
>
> ***Company answer:*** The primary drivers for the project's business case are provided on page 2 of Attachment 5 [Provided in response PS DR 42] and include: Consolidate Construction & Maintenance and Relay into one building, Facilities are over 20 years old and current crew and yard laydown space is limited, and Transmission headcount to increase, opportunity to meet those needs. Therefore, the business operations and addressing growth (or space limitations) was the driver and not based on a capital investment by Duke Energy to realize cost effectiveness of the new facilities over the existing facilities or lease costs (which isn't applicable).[11]

Q. Why are you recommending disallowance of Project Florence's costs and their removal from rate base?

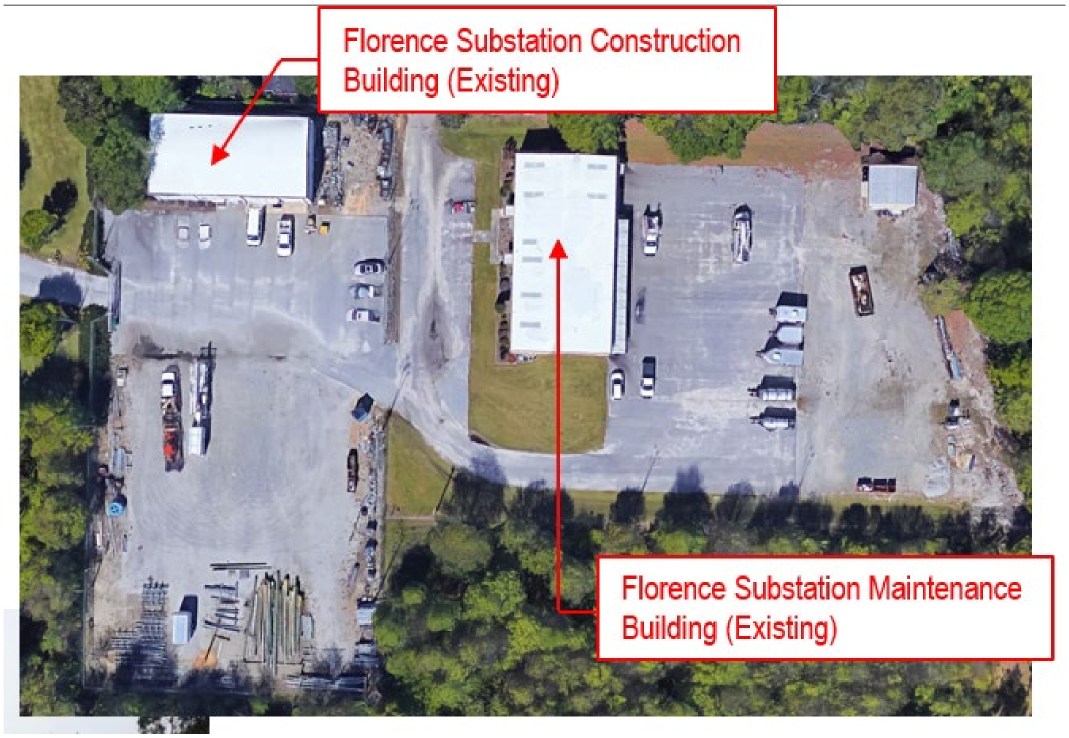
A. The information, or lack thereof, DEP provided through discovery does not justify inclusion of the project's costs in rate base. The fact that an asset (building in this case) is 20 years old does not mean it cannot continue to be useful and serve its intended purpose. Operational challenges are not a reasonable justification to ask ratepayers to pay for a ~$14 M dollar investment, particularly when no analysis (economic or otherwise) was performed (at least none that was provided in discovery) to demonstrate how the functionality of pre-existing buildings was inadequate or inefficient, or how the new building would satisfy or eliminate them. In fact, the O&M

[11] See Company response to PS DR 90-1.

for the new building is estimated to be 25% greater than it was for the pre-existing buildings combined.[12]

The aerial photograph below is of the pre-existing Construction and Maintenance buildings, including vehicles and equipment that provide a sense of scale.

Figure 1 Original Project Florence Site



The photograph below shows the new Project Florence building in the foreground with the pre-existing Construction building in the back left (underneath the Public Staff Data Request 42 notation) and the pre-existing Maintenance building to the right of center in the background. A

[12] See Company response to PS DR 90-12.

comparison of the first and second photographs demonstrates the scale and increase to the size of the workspace achieved by the new building.

Figure 2 Post Project Florence Site

A more recent aerial view below shows the new building after the Construction and Maintenance buildings were demolished. Several other new Duke Energy buildings are visible in the general vicinity of the new Project Florence building as well.

Figure 3 Aerial View of Project Florence

B. Project Walter

Q. Please discuss Project Walter and your findings and recommendations.

A. Duke Energy has built or renovated several energy control/operations centers across the enterprise. As the Commission is aware, DEC built and placed into rate base a new Electric System Operations (ESO) Control Center, also known as the Carolinas West Primary Control Center in the 2017 DEC rate case (Docket No. E-7, Sub 1146). In this docket, DEP has requested approval of the costs of Project Walter, a new ESO for DEP. Project Walter was designed and constructed to conduct two primary operations: the Energy Control Center (ECC) will operate DEP's bulk electric (transmission) system and the Distribution Control Center (DCC) will manage the Company's distribution system. The facility is designed to have multiple ancillary functions as well, one of which is a backup control center for DEC.

The Company closed the project to plant in November 2022 and is seeking to recover ~$114.8M for costs associated with this project. Based on my review of the project, I do not take issue with its need. However, the building is not currently used and useful because it is not operating as intended at this time. Therefore, it should not be included for cost recovery in the Base Case. On Thursday, February 23, 2023, the Public Staff conducted a site visit and multi-hour detailed walk down of the facility and observed the current state of the building and the construction progress. During the site visit, I observed one security guard, one person in the maintenance technician offices, and three additional people in the general support areas performing work functions. No workers were present in the ECC or DCC areas.

The Company expects staff to have moved in and each of the primary functions of the building to have achieved overall functionality on **[Begin**

Confidential] [redacted] [End Confidential] for the DCC and [Begin Confidential] [redacted] [End Confidential] for the ECC. A primary reason for these functionality dates is because the building has yet to be [Begin Confidential] [redacted] [End Confidential].

Given the timing of the project and when it will begin functioning for its primary purposes, this project is more appropriate for inclusion in Rate Year 1 (October 1, 2023 – September 30, 2024) of the MYRP.

Q. Was DEC's Carolinas West Primary Control Center fully functional when it was included in rates in DEC's 2017 general rate case?

A. No. However, the circumstances of the DEC and DEP ESOs differ. The DEC ESO included other aspects of utility operations that were functional, aspects which are not part of DEP's Project Walter. Specifically, the DEC control center includes monitoring and dispatch enterprise-wide regulated renewable energy resources and security. In addition, and importantly, at the time of the previous DEC rate case in question, there was no proposed MYRP to address projected year cost recovery.

---

[13] See Company Confidential response to PS DR 231-7.

[14] See Company Confidential response to PS DR 231-8.

C. Materials and Supplies Inventory

Q. Briefly describe materials and supplies inventory.

A. For purposes of my testimony in this case, I define materials and supplies (M&S) inventory as spare parts to maintain the reliability and serviceability of generating plants. M&S inventory can also include costs associated with future projects, as the Company needs to procure parts in advance of the time they will be physically installed.

Q. Have you provided testimony on this issue in previous rate cases?

A. Yes, I provided detailed testimony describing M&S inventory and its different categories in DEP's last two general rate cases, Docket No. E-2, Subs 1142 (Sub 1142) and 1219.[15]

Q. Are the concerns you have now similar to the concerns you raised in these previous rate cases?

A. Yes. In both previous rate cases I testified that if the inventory could not be used for extended time periods, those parts (inventory) are unavailable for use, and ratepayers should not be burdened with the associated costs of the inventory being included in rate base for purposes of rate making.

[15] Docket No. E-2, Sub 1142, *Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, Testimony of Evan D. Lawrence and Dustin R. Metz, p. 11-18, December 6, 2019; Docket No. E-2, Sub 1219, *Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, Testimony of and Dustin R. Metz, p. 23-28, April 13, 2020.

Q. Please describe the overall amounts in M&S inventory from prior rate cases and in the present rate case.

A. See the table below for costs per year per category.

Table 1 M&S Inventory Costs

M&S Inventory												
Hold Category	Repair Hold			QA Hold			EC Hold			Hold Sum		
Years on Hold ≥	2	4	6	2	4	6	2	4	6	2	4	6
Test Year 2016 ($M)		1.6	0.9		8	1		7.1	0.9	27.2	19.5	2.8
Test Year 2018 ($M)	7.5	3.2	1.9	8	5.7	4.8	15.3	13.7	10.5	30.8	22.6	17.2
Test Year 2021 ($M)	6.2	3.4	2.4	5.7	4.6	1.5	13.5	12.2	10.6	41	33.3	15.5
Change 2016 to 2021 ($M)	6.2	1.8	1.5	5.7	(3.4)	0.5	13.5	5.1	9.7	13.8	13.8	12.7
Change 2018 to 2021 ($M)	(1.3)	0.2	0.5	(2.3)	(1.1)	(3.3)	(1.8)	(1.5)	0.1	10.2	10.7	(1.7)

Overall, while some category values have increased and others have decreased, from the 2018 test year to the 2021 year, there was a relative decrease in repair hold and quality hold in terms of dollar value but an increase in the total hold sum amount also occurred.

Q. Which M&S inventory cost categories are you recommending for disallowance?

A. Similar to my testimony in both prior DEP proceedings, I recommend disallowance of four-year Repair Hold and Quality (QA) Hold costs associated with inventory that has been in a hold (unusable) status for four years or more ($3.4 M+ $4.6 M = $8.0 M).

I have provided an adjustment of $8.0M reduction to nuclear M&S inventory to the Public Staff Accounting Panel for incorporation in their schedules.

Q. Why are you not recommending removal of Engineering Change (EC Hold) M&S inventory that has been in a hold status for 6 years or more?

A. After evaluation and consultation with the Company, I understand much of the inventory is this specific category to be related to one-off, large dollar purchases that have long lead times and/or is no longer commercially available; therefore, I am not recommending an adjustment at this time.

Q. Do you have any other recommendations or comments at this time based on your review of the M&S inventory?

A. Yes. I have one additional finding related to static inventory which was not removed from the test year base rate costs in the initial filing. Static inventory can consist of spare parts that were acquired for anticipated repairs to one piece of plant equipment that has subsequently been replaced with a different piece of equipment or no longer has a useful purpose. Static inventory is not usable on the new equipment or elsewhere in the plant or fleet. Based on my findings and follow-up discovery, the Company self-identified ~$282K of stranded inventory that should have been removed from inventory for the period 2017-2021 but was not. The Company has since made the required adjustment in a supplemental filing.[16] This is a relatively minor finding, but it is my understanding that the

[16] Reference Company response to PS DR 72-3(c)(i), and Company Proforma NC-2080.

Company is evaluating actions to strengthen the static review process going forward which could mitigate future occurrences.

D. Reserve End of Life for Nuclear, NC-2120

Q. Please describe the purpose of the Company's Reserve End of Life for Nuclear pro forma adjustment.

A. The Company's adjustment calculates the cost and value of certain elements of a nuclear power plant, including the unused energy of the last nuclear fuel bundle and nuclear M&S inventory (spare parts).

Q. Do you recommend that the Company's pro forma adjustment be modified?

A. Yes. I am proposing the same adjustment to M&S inventory and salvage value that I recommended in Sub 1219.[17]

First, I recommend that the end-of-life inventory (the M&S Inventory) be reduced on a pro-rata share across all nuclear generating assets as per my previously discussed M&S Inventory adjustment in this current case. This adjustment will result in an overall reduction of the total amount of M&S Inventory for this line item. Second, I propose a positive salvage value be assigned to the M&S Inventory. In DEP's Sub 1142 rate case, Duke used a 20% salvage value, but in this case and as well in the Sub 1219 rate case,

[17] Docket No. E-2, Sub 1219, *Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, Testimony of Dustin R. Metz, p. 30-32, April 13, 2020.

the Company reduced that value to 0%. However, the Company did respond in rebuttal in the Sub 1219 case that it, "generally agrees that there will be some small amount of salvage value…at its end of life".[18]

Q. Why is it appropriate to use a salvage value of the inventory at the end of the plant's life?

A. Given the uncertainty of which nuclear generating units will seek and ultimately obtain a subsequent license renewal, I recommend a salvage value of 5% in this case, and for it to remain static going forward until the generating units are retired. Motors, electronics, bare stock, forgings, and assorted equipment, which are all part of the M&S inventory, will have a minimum salvage or recycle value. M&S inventory, generally speaking, consists of warehoused controlled pieces of equipment that do not require significant amounts of labor and resources to disconnect and remove; thus, the equipment can be removed from the warehouse shelving via boxes, pallets, or rigging and loaded onto a vehicle for salvage.

The Company's test year nuclear M&S inventory across its three nuclear stations (four generating units) totals ~$389M, prior to any Public Staff adjustments in this case. It is illogical to assume that out of $389M in M&S inventory, most of which, if not all, is in a warehouse or storage/laydown

[18] Docket No. E-2 Sub 1219, Rebuttal Testimony of Kelvin Henderson, p. 8, ln 9-10.

yard and generally protected from the elements, will have no salvage or scrap value.

I have provided this adjustment to the Public Staff Accounting Panel.

II. Fossil Generation Trends

A. DEP's Historic Operations of its Generating Fleet

Q. Did you review the historic operations of the Company's generating fleet?

A. Yes, I reviewed the historic operations of the Company's generating fleet since the Sub 1219 case, as well as other discrete metrics over approximately the last decade. Part of the review considered overall system reliability, service quality, and the reasonableness of using the Company's test year O&M costs as a proxy for expected future costs. The review also required analysis of multiple years of data for trending purposes, spanning multiple rate case periods[19] and included categories such as O&M costs, staffing, and unit outage rates.

Q. Please summarize your review of the Company's historic operations of its generating fleet.

A. The primary purpose of this review was to determine if there has indeed been a change in the historic operation of the generation fleet, and if so, the

[19] Docket No. E-2, Subs 1142, 1219, and 1300.

direction of the change. This review was not to determine the reasonableness or prudence of the historic operations of these fleets. Therefore, the results of my review should not be interpreted to imply that the Company has been imprudent. With that said, trending data suggest that certain aspects of generating unit performance have degraded in recent years, causing concern about the potential for continued degradation and the Company's ability to ensure future system reliability, which may necessitate modifications to utility resource planning. However, part of my review revealed that the Company changed its method of reporting certain generation criteria in or around 2016, therefore causing further uncertainty as to the accuracy of the data or whether trends can be identified using data from a decade ago.

My review led me to conclude that the Company's fossil generating fleet performance (combined cycle (CC), combustion turbines (CTs), and coal) has degraded (trended negatively) over the last decade (relative change year over year), with the performance of some units degrading more than others. Should these negative trends continue, they may further impact reliability or the ability to perform daily economic dispatch, especially as these units are required to perform in a much different manner than originally designed and as other generation units are removed from service. Coal generation units appear to have had the most significant downward trends in performance, followed by CC units, and then CTs.

It is important to note, depending on the generating statistics being evaluated, different conclusions may be reached. The review included not only a review of specific generating unit operational performance metrics, but also staffing, O&M, and other factors, requiring multiple discussions with Company staff.

Q. Please provide a more detailed description of your review of the historic operations of DEP's generating fleet.

A. Part of the Public Staff's discovery focused on various North American Electric Reliability Corporation (NERC) generating unit performance statistics as defined in NERC's 2023 GADS Data Reporting Instructions "Appendix F: Performance Indexes and Equations."[20] When analyzing outage trends, two important factors for each unit are its equivalent availability and its outage rate exclusive of planned outages.[21] My overall review considered the weighted average of each of the Company's generating units by type (e.g., CC, CT, and coal) and nameplate rating.

My initial evaluation of unit availability focuses on unit equivalent availability factor (EAF), which is different than the availability factor (AF). The EAF metric measures unit performance by determining the percentage of time

[20] https://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Appendix_F_Equations_2023_DRI.pdf

[21] Planned outages typically allow the Company to perform major plant maintenance work and inspections that occurs on a nominal cyclic pattern and will likely have a predetermined duration.

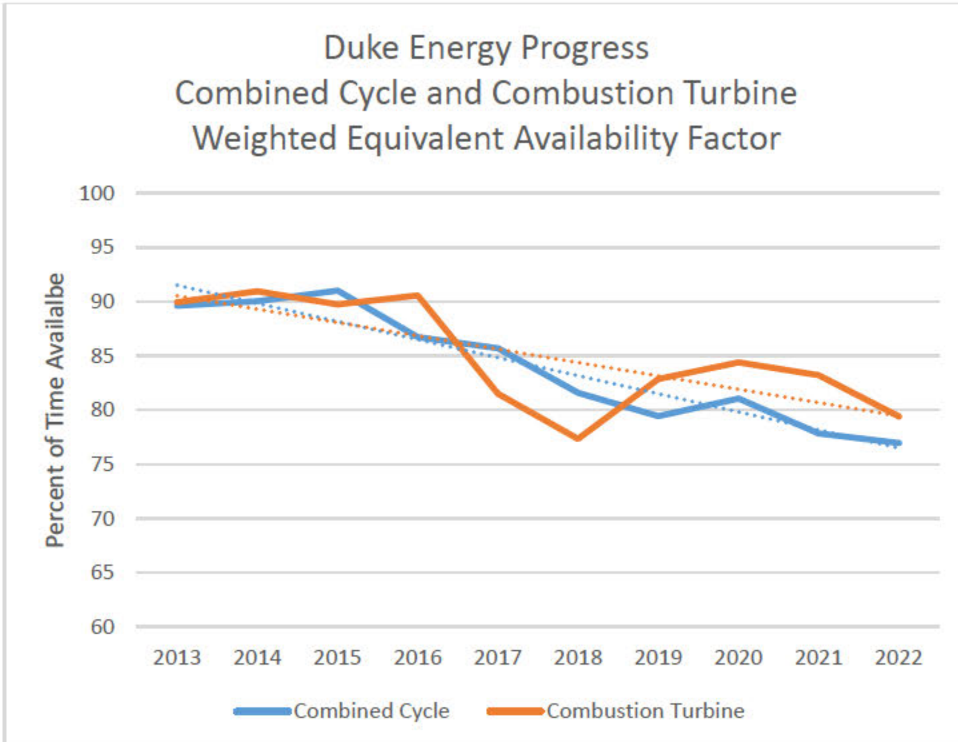
that a unit is available without any reductions in nameplate capacity,[22] whereas the AF measures unit performance by determining the percentage of time a unit is available regardless of whether it is operating at its actual nameplate rating or at a deration to nameplate. An EAF of each generation unit is weighted (WEAF) on the contribution of each unit's nameplate rating to similar Company owned assets. The WEAF is most appropriate for purposes of my review because unit derates may occur in a given hour, or even sub-hour, in order to balance system needs or to allow for economic dispatch. Unit derates at DEP's Mayo and Roxboro coal generating stations were a factor in the recent 2022 Winter Storm Elliott event as well as at certain generation plants in DEC's service area.[23] Unit derates can be caused by many factors, including boiler tube leaks, excessive water temperatures, variations in ambient air temperatures, and water chemistry issues.[24] The graphs below show the annual WEAF trends of the Company's fossil fuel generating plants since 2013.

[22] The reductions to nameplate capacity can be for outages or derates (planned or unplanned) for the following reasons: maintenance, forced, unforced, or seasonal. A derate, which is a temporary reduction in nameplate capacity, prevents a generating unit from being dispatched at its full output.

[23] The Public Staff is currently reviewing the impacts and causes of the unit outages from the December 2022 event, including the detailed discovery responses provided by the Company in Docket No. M-100, Sub 163.

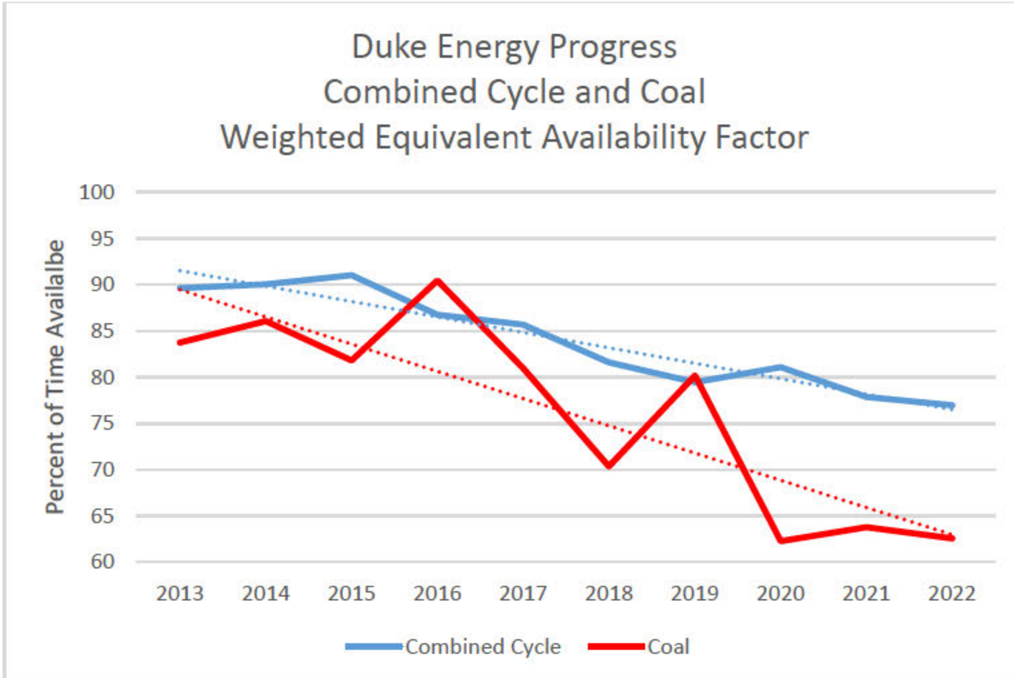
[24] Equivalent availability and other reporting metrics have been discussed in prior avoided cost filings. Notably, Duke Energy's most recent avoided cost filing summarized reliability metrics. *See* Joint Initial Statement and Proposed Standard Avoided Cost Rate Tariffs of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (DEC and DEP Joint Initial Avoided Cost Statement), at 19-21, filed on November 1, 2021, in Docket No. E-100, Sub 175; *See also* Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's 4th Submission of Responses to Public Staff's Data Request No. 2, PS DR 2-25, for a description of outages and derates during Winter

Figure 4 WEAF for Natural Gas Generating Fleet



Storm Elliott, filed in Docket No. M-100, Sub 163, under seal on Feb. 9, 2023, and confidentially on Feb. 10, 2023.

Figure 5 WEAF for Natural Gas Combined Cycle and Coal Generating Fleet



A second factor discussed extensively in the Public Staff's[25] and DEC's and DEP's comments in the last two avoided cost dockets[26] is the weighted equivalent unplanned outage rate, which is similar to the weighted equivalent unplanned outage factor (WEOUF), which does not reflect the impacts of or meet the requirements of standard planned outages. The graphs below display the Company's fossil generating fleet's WEOUF trends.

[25] Public Staff's Initial Comments, 15-16, filed Feb. 24, 2022, in Docket No. E-100, Sub 175.

[26] DEC and DEP's Joint Initial Avoided Cost Statement, 19-21.

Figure 6 WEUOF for Natural Gas Generating Fleet

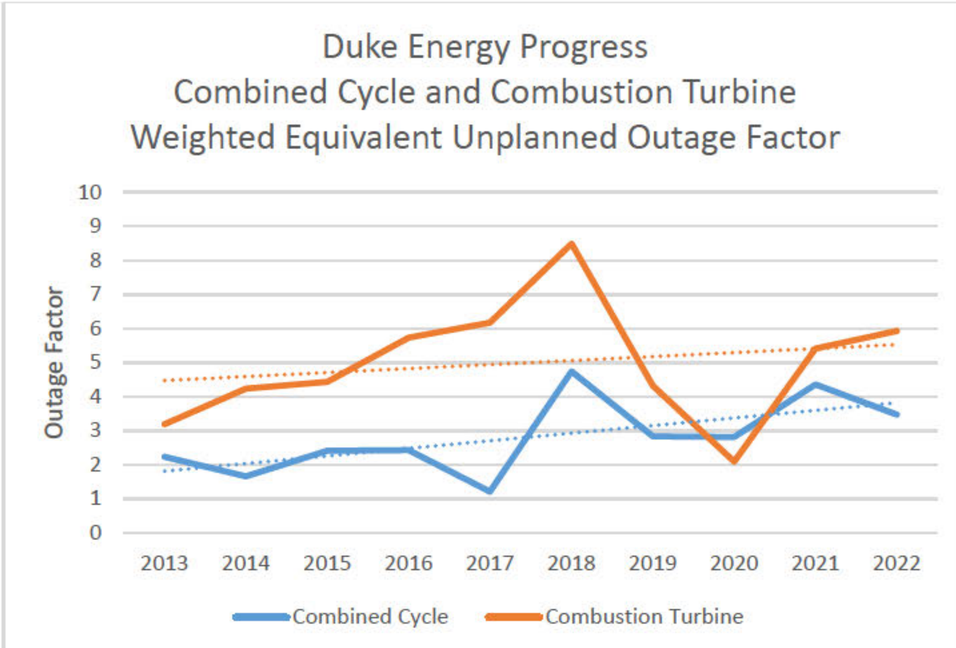
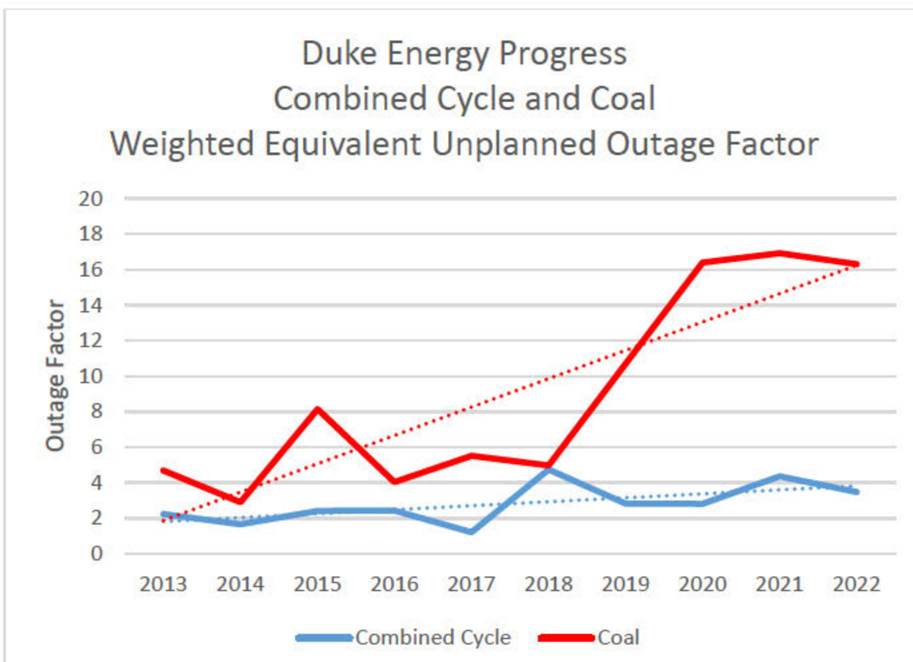


Figure 7 WEUOF for Natural Gas Combined Cycle and Coal Fleets



Overall, CT unit outages appear to vacillate more with a relatively small increase in unplanned outages from 2013 to 2022, whereas coal and CC units have seen a near constant increase in unplanned outage events, and declining availability. CCs and CT units combined show a relative increase in WEUOF for 2018 followed by a significant decrease the following year, whereas coal generation remains elevated post 2018.

Q. What are the key observations from your review of this data?

A. As a result of current trends, the Company should re-evaluate its fossil-based generating resources' effectiveness and unit availability in its upcoming Carbon Plan Integrated Resource Plan. This may result in a change of the effective load carrying capability or an increase in the unit outage rates of fossil generating units, which could lead to the need for a higher reserve margin. This result would be unfortunate as ratepayers are already paying for system reliability in base rates, but the decline in unit performance and availability should not be ignored.

I am not requesting that Duke automatically make more capital improvements to the units at additional costs to ratepayers; I am merely highlighting concerns about system reliability and wish to emphasize the necessity that proposed MYRP projects be scrutinized to determine whether they will improve reliability or contribute to further decline. If a particular MYRP project (even if not at a generating unit) does not improve system reliability, the Company should question whether the project is necessary or should be modified or re-prioritized.[27]

Q. What O&M trends did you observe?

A. I reviewed trends in non-fuel O&M spend by generation type for the Company's entire fleet by plant. My review of the total amounts of non-fuel O&M spend for specific business groups (Nuclear, Coal, Natural Gas, Solar, Hydro, Transmission, and Distribution) shows that O&M costs have declined in all business groups except solar and hydro after the test year of the last two DEP rate cases.[28] I understand that capital projects sometimes result in non-fuel O&M cost savings and that 2020 was an anomaly due to the COVID-19 pandemic, but the trend of cost reductions after a test year is striking. The table below shows the nominal and present value (2021 test year) annual non-fuel O&M spend of specific business groups.[29]

---

[27] For example, the Company's February update included ~$170M for structures, building renovations, administrative buildings, and new facilities. While these capital projects may be of value, these items could be replaced with generating and reliability investments if a shorter-term solution is needed to maintain and improve system reliability. Using project costs in the Company's MYRP proposal, the Company could build capacity and energy projects, e.g., approximately three 30.5 MW battery projects (using the Craggy project as a proxy) that may be more of a priority than other projects in the MYRP. The Company must also balance whether to invest in assets nearing retirement with the total bill impacts to ratepayers, as well as the need to meet the winter morning peaks of the system.

[28] DEP's two prior rate cases and the current rate case had test years of 2016, 2018, and 2021, respectively.

[29] Source: Company responses to PS DR 21-3 & https://fred.stlouisfed.org/series/FPCPITOTLZGUSA .

Table 2 Annual Non-Fuel O&M Spend of Specific Business Groups

	As Spent	Adjusted for Inflation	
	Total	Total	
2015	$ 1,004,999,282	$ 1,099,154,987	
2016	$ 979,737,963	$ 1,058,025,763	Test Year Sub 1142
2017	$ 892,679,133	$ 943,476,913	
2018	$ 950,737,357	$ 980,320,862	Test Year Sub 1219
2019	$ 904,496,502	$ 915,760,354	
2020	$ 814,501,428	$ 814,501,428	
2021	$ 850,214,815	$ 850,214,815	Test Year Sub 1300
2022	$ 896,126,415	$ 847,735,588	

From 2015 through 2022, the total present value of all non-fuel O&M costs declined year over year by ~3%. Notably, the fossil generating fleet O&M spend declined ~4% year over year, some of which resulted from capital project improvements. However, declining WEAFs over the same period indicate lower reliability, not greater efficiency. Further, annual fuel filings for DEP and DEC, as well as transfers of non-firm energy via the Joint Dispatch Agreement (JDA), show an ~2% reduction in DEP's total energy generation from 2019-2020. During that same time, the percentage of energy from DEP-owned generation dispatched to serve DEC via the JDA increased by ~11% or 572,975 megawatt-hours (MWh) even though DEC decreased its JDA transfers to DEP by ~46%, a reduction of 901,996 MWh relative to the prior year.[30] [31]

[30] Generation data and JDA transfers were taken from each year's annual fuel cases and the 12-month ending fuel reports filed with the Commission.

[31] In other words, energy transfers from DEP to DEC were increasing at a time when DEP's generating units were less available and some of which were generating less energy. Had the units had a higher availability factor, it is reasonable to assume that energy transfers from DEP to DEC

The WEAF for the coal generating plants declined from ~80% pre-2020 to a single year value of ~62% and remained at the lower value for 2022. In addition, non-planned unit outages increased during the same period in question, while total O&M spend decreased in aggregate from the amounts reflected in the 2019 rate case (2018 test year), which were used to set an expected or reasonable level of ongoing costs. Further, the lower O&M costs, which can benefit ratepayers in the short run due to lower operating costs, may have a longer-term negative impact on reliability as reflected by declining unit performance for certain generating groups. The Public Staff settled with DEP on an amount for O&M in the last rate case that we expected would be sufficient for the Company to maintain its generating fleet and ensure system reliability and availability for economic dispatch. While the Public Staff encourages the Company to look for cost savings that occur organically without impacting reliability, cuts in O&M spending immediately following a general rate case that established those levels of ongoing O&M raises questions. If the Company planned to reduce O&M expenses across its generating fleet after the test year, it should have filed a pro forma adjustment to reduce the level of O&M costs in the prior rate case. That did not happen, and as a result, its ratepayers have paid a level

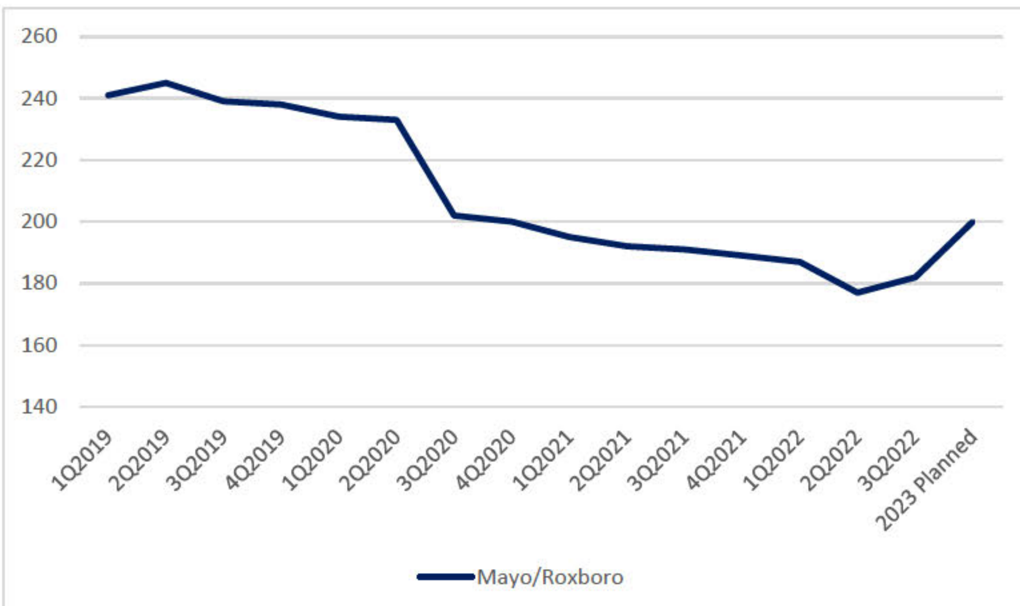
---

would have been at an even greater level, thus improving total system (DEP and DEC) economy and reliability annually.

of O&M costs for the last three years above the Company's actual O&M spend while the performance of certain generating units declined.

The graph and table below show that the Company decreased internal labor at the Roxboro and Mayo generating plants, DEP's remaining coal plants, over the last three years, while unplanned outages remained high and the EAF remained low as compared to the prior seven years.[32]

Figure 8 Mayo and Roxboro Generation Staffing



[32] See Company response to PS DR 6-1 and 6-2.

Table 3 Summary of Outage and Generation Metrics of DEP Coal Plants with Energy Transfers and Staffing

Outage and Generation Metrics of DEP Coal Plants with Energy Transfers and Staffing							
Year	Equipment Availabilty Factor	Unplanned Outage Factor	Present Value Non-Fuel O&M	Coal Energy Generation MWh	Total Energy Produced MWh	JDA Transfer DEP to DEC MWh	Head Count Mayo & Roxboro
2013	83.73	4.69		13,085,888			
2014	86.06	2.9		15,389,417			
2015	81.79	8.14	$ 171,587,025	12,151,478			
2016	90.45	4.04	$ 122,813,921	10,321,577	67,619,619		
2017	80.96	5.52	$ 106,067,094	7,433,789	70,851,204		
2018	70.35	4.98	$ 135,105,162	7,419,209	70,945,428	5,418,223	
2019	80.16	10.68	$ 130,755,161	8,472,597	69,839,648	5,338,351	241
2020	62.27	16.39	$ 96,975,027	5,884,784	68,264,626	5,911,326	217
2021	63.78	16.92	$ 107,492,399	6,822,299	70,153,063	5,779,517	191
2022	62.55	16.31	$ 107,178,951	6,551,940	70,296,361	7,369,876	182

Q. Do you believe there is a connection between the declines in the reliability of the fossil fuel fleet with the Company's System Average Interruptions Duration Index (SAIDI)?

A. Yes. While the WEAF is a metric of generation fleet performance, changes in SAIDI are most often affected by the performance of the transmission and distribution (T&D) systems. Thus, changes in these two metrics may be indicative of increases or decreases in capital spend or O&M. Public Staff witness Tommy Williamson discusses DEP's SAIDI performance in more detail in the Service Quality section of his testimony.

The Company's generating fleet (Nuclear, Steam-Coal, and possibly Natural Gas) will receive less funding in the MYRP as compared to the Base Case. The table below compares the Base Case spend on capital investments with the aggregate MYRP projections.[33] The historic review is covers the first 30 months of capital spend closed to plant after the Sub 1219 update cutoff date; I will update this table in supplemental testimony.[34] Company updates of more months of the historic rate case will increase the column listed as Sub 1300 Base Case.

Table 4 Base Case spend with MYRP Projections

	30 Months	36 Months
Type of Capital Plant	Sub 1300 Base Case	MYRP, RY1-RY3
Elec - Distribution Plant	$ 1,446,121,087	$ 1,916,311,509
Elec - General Plant	$ 320,680,594	$ 325,459,818
Elec - Hydraulic Production Plant	$ 80,625,744	$ 167,335,125
Elec - Intangible Plant	$ 132,598,614	$ 96,152,354
Elec - Nuclear Production Plant	$ 398,316,700	$ 323,396,382
Elec - Other Production Plant	$ 316,594,955	$ 779,457,761
Elec - Steam Production Plant	$ 87,405,199	$ 32,813,897
Elec - Transmission Plant	$ 573,029,915	$ 1,152,877,089

Q. Based on your observations and trends of historic generating unit reliability, what are your recommendations in this general rate case?

A. I am not proposing any adjustments to the Base Case capital plant spend for coal, nuclear, and natural gas generating assets. I do request that the Company address in its rebuttal the following topics related to generating unit performance trends:

---

[33] MYRP Projects are based on the February 2023 DEP update.

[34] The Public Staff received updates to PS DR 11-1 with December projects closed to plant on February 27, 2023. The Company reported an additional ~$7M in Steam Plant additions (closed to plant) just for the month of December. The Company has also closed to plant ~$5M in Steam Plant for the month of January 2023, which is still under review and audit.

- The Company's plans to prevent further degradation of the generating unit performance of its coal fleet, and the steps being taken over the same period to improve upon its coal generating unit reliability and availability.
- The Company's spending priorities among business groups in the MYRP, given decreasing SAIDI numbers (positive reinforcer) from 2017 to present, concurrent with negative trends in coal and natural gas generating unit performance.
- Decreases in head counts (employees) at generating plants continuing year over year while generating unit performance trends downward.
- Shorter, stop gap measures to ensure system reliability and maintain more favorable economic dispatch, given that the Company's coal plants may be at a terminal phase in their service lives.

Q. You stated previously in your testimony that depending on which generating statistics are evaluated, different conclusions may be reached, could you please expand on that statement.

A. During the Public Staff's review of the reliability of the fossil fuel fleet, the Company discussed different metrics that it has historically used, including the equivalent forced outage factor (EFOF),[35] which measures only forced

[35] **[Begin Confidential]** [redacted] **[End Confidential]** Reference Company Confidential response PS DR 137-17.

outages. While the number or duration of forced outages may decline, it is important to examine the reason why the decline occurred and any changes to the number and duration of other types of outages.

For instance, a reduction in forced outages could occur, but it could be due to an increased number of maintenance outages or maintenance outages (or even planned outages) of longer duration due to the removal of generation assets from economic dispatch on any given day. Focusing on one single metric can obscure the need for further improvements to generating unit reliability or the economic impact of the daily least cost dispatch of the entire fleet.

B. Coal Reliability Assurance: NC-2160

Q. Did you review the Company's proposed pro forma NC-2160 filed in its February 2023 supplemental testimony and update?

A. Yes, but I was unable to complete my audit of the proposal prior to filing this testimony due to time constraints. The Company's proposed NC-2160 pro forma was to request additional O&M to supplement the test year spend for coal reliability assurance.

Q. Based on the information you have reviewed, please provide your preliminary opinion of the pro forma adjustment proposed by the Company.

A. In general, there is merit to the Company's proposed adjustment based on the coal unit availability and outage rates discussed earlier in my testimony. However, the approved revenue requirement from the Company's last two general rate cases included a level of ongoing generating plant non-fuel O&M expense, which the Company reduced (particularly for its coal generating fleet) the very next year.

My earlier testimony pointed out the reduced head counts at Mayo and Roxboro since 2019. In prior rate cases, the Commission approved retail rates that included an estimated or expected level of O&M spend (including staffing). Once rates were approved, the Company proceeded to reduce the level of O&M spend, in part by reducing staffing. In this case, Company has identified a need to increase spending above the test year level.

The Company's proposed pro forma (NC-2160) uses an estimated DEC-DEP aggregate amount of discrete spend over various categories. The Company then allocated a portion of the aggregate pro forma to DEP based on its share of the total number of coal generating stations located in the utilities' combined service areas. I do not believe cost sharing between DEC and DEP should be based on a simple ratio of the number of generating plants for each utility. The coal units in question differ in capacity size, efficiency, geographic location, and number of employees. Furthermore, the Company's proposed 60% allocation of DEC-DEP aggregate amount appears to be based on the number of coal plants and respective units in each utility. DEC has more coal plants and more units than DEP, but the Company assigned a higher percentage to DEP. A more tailored and unit-specific adjustment for each coal generating station is more appropriate, but I was not able to propose an alternative modification to the DEC-DEP cost sharing mechanism at this time. DEP should respond through rebuttal with a more tailored and unit-specific adjustment as well explaining why DEP was assigned 60% of the total cost when DEC has more units.

The table below breaks down the Company's proposed costs to DEC and DEP by year.

Table 5 DEP and DEC Coal Fleet Costs by Year

Reliability Assurance Cost Category	2023	2024	2025
Major Components Reliability Threats Analysis	$3.9	$4.1	$3.5
Winterization O&M	$1.9	$4.8	$5.8
Operator Workarounds / Reliability Improvements	$4.7	$4.5	$6.3
Staffing	$5.9	$5.9	$7.5
Repair Hold	$4.3	$1.7	$1.7
Reliability Assurance Total	**$20.7**	**$21.0**	**$24.8**
For Rate Case (Proforma) Purposes	**2023**	**2024**	**2025**
DEP Share - 60% (5 Units)	$12.4	$12.6	$14.9
Mayo - 1/5 Units	$2.5	$2.5	$3.0
Roxboro - 4/5 Units	$10.0	$10.1	$11.9
DEC Share - 40%	$8.3	$8.4	$9.9
Total	**$20.7**	**$21.0**	**$24.8**

Besides the concerns identified above, I am also recommending several other modifications to NC-2160.

DEP should have already completed the Reliability Threat Analysis as a part of standard utility practice, with any update or modification included in the 2021 test year expenses. The Company should have completed this analysis following the 2014 and 2015 Polar Vortexes, the 2018 cold weather event, and in lessons learned from Winter Storm Uri in early 2021. As a result, this cost should be excluded from any proposed pro forma adjustment.

Similar to the Reliability Threat Analysis cost, the Winterization O&M work should have been completed as well. Year over year changes and modifications to O&M plans should be standard business practices, and do not justify an elevated level of spend. However, based on recent historic unit performance, a level of incremental spend may be justified as part of the normal course of business. Based on my preliminary review I support the inclusion of the 2023 incremental amount of $1.9M on a going forward basis, noting that I have yet to review the supporting information behind this value. I do not support the rapid increases in O&M spend proposed for 2024 and 2025, to $4.8M and $5.8M respectively. My preliminary recommendation is that $1.2M[36] is a reasonable estimate of incremental

[36] $1.9.M (DEC + DEP system) x 60% = ~$1.2M (DEP system, rounded up).

spend for ongoing O&M at the coal generating fleet. I may update this recommendation following completion of my review.

As for Reliability Improvements, the majority of the costs appear to be capital-related rather than O&M. The Company has the ability, via the MYRP process, to propose future capital investments for cost recovery in this case. The Company filed its initial MYRP proposal in October 2022, and an update in February 2023. As a result, this line item should be excluded from the pro forma adjustment and included in the MYRP if appropriate.

While the reliability and availability metrics and the concurrent staff reductions cited earlier in my testimony may suggest the need to increase staff at these coal generating plants, the ongoing level of O&M costs included in the Sub 1219 rate case also included around 240 employees. Yet, the following year, the Company reduced staff at Roxboro and Mayo to ~200 people total and are now down to ~180-190 employees. As such, there is no certainty that the Company will hire and continue to employ the proposed level of increased staff at these plants. Further, the Company proposed this pro forma as a DEC-DEP joint effort with each receiving a pro-rata share. It is unclear how the expected upcoming closure of DEC's Allen Steam Station will provide potential synergies or staff relocation, mitigating potential impacts of this adjustment. For purposes of establishing rates, I propose a pro forma increase of half of the Company's 2023 staffing request, rounded to $3M (DEC + DEP system) or $1.8M (DEP system).

I recommend that the Commission reject the proposed Repair Hold (RH) category adjustment. Ratepayers have already paid for a level of inventory management and control through base rates, and the proposed first year spend of $4.3M and $1.7M in the following two years appears to be an attempt to clear backlog of a larger volume of inventory (spare parts) to be repaired. The Company has not justified an incremental spend above what is already included in the 2021 test year. Accordingly, this line item should be excluded from the pro forma adjustment.

I provided to the Public Staff Accounting Panel a modified NC-2160 pro forma adjustment to increase annual O&M for DEP's coal generating fleets to $3M (DEP system level), resulting in an ~4.5% increase in the Company's annual non-fuel O&M spend. As filed, the Company's pro forma results in a near 19% increase (present value) in a single year for non-fuel O&M at two generating stations.

C. Contributions in Aid of Construction (CIAC)

Q. Did you review CIAC in this case?

A. Yes, the Public Staff reviewed DEP's CIAC and had several discussions with the Company on the topic.

Q. Please define CIAC and its relationship to your review in this rate case.

A. CIAC is third party funding of utility capital projects, usually new construction. The third party is typically a utility customer who has requested work to be done by the utility.

For purposes of my review, I focused on CIAC projects completed since the Company's last rate case, including DEP's projects to interconnect third-party Qualifying Facility (QF) generation. Historically, a QF developer is responsible for the cost of network upgrades required for interconnection, and these costs are not socialized to all ratepayers unless otherwise permitted by law. As part of this process to determine the CIAC, the Company performs a study to determine what network upgrades are necessary for the safe and reliable interconnection of the developer's project. DEP then charges the third-party developer for the construction costs of the identified network upgrades. Ultimately, ratepayers should be held harmless if the network upgrades are paid for in whole by the developer, plus any additional true up costs, once the project is online. The Company historically recorded developer CIAC payments as revenue, rather than an offset to rate base.

The Company self-identified this CIAC issue in a 2019 audit but deemed it not to be material.[37] The Company revisited this topic during a 2022 follow-

[37] "The 2019 audit found that liability accounts holding generator deposits have significant aging balances, and reconciliations were performed inconsistently. In addition, the audit found that

up audit and made a process change at that time, setting a June 2023 deadline for documenting processes and defining roles and responsibilities.[38] I attempted to determine the magnitude and resulting rate impact of this issue; however, more time is needed to audit, validate, and review this issue given the complexity. The Public Staff Accounting Panel addresses the accounting aspects of this finding in their testimony.

---

accounting for Distribution interconnection construction contributory payments was incorrect. The audit stated that the annual impact of this error was not material to the financial statements. The management action for the account reconciliations was for accounting and finance to implement consistent account reconciliations in accordance with company policy. As it relates to accounting for distribution contributory payments for distribution interconnection facilities, it was determined that the company's practice to record contributory payments from generators to the income statement as Other Revenue while costs incurred to complete construction are charged to CWIP balance sheet accounts was incorrect. Instead, the audit stated that the contributory payments should be recorded to CWIP. At the time, the balance in CWIP was immaterial and received a low priority categorization." See Company response to PS DR 189-1.

[38] The Company's response further stated, "The company did stop recording contributory payments to revenue and started recording to the 0242-liability account initially with the intent of journal entries being performed to move the deposit to the (0107/0101/0106) capital projects. Due to high volume and difficulty implementing process changes, a regular cadence to reclass the contributory payments to the capital projects did not occur. An entry to reclass the upgrade deposit also did not occur for the same reasons. In 2022, a second follow up to the 2019 internal audit was performed. The audit recognized that the process improvements have strengthened tracking of the interconnection financial activity. However, the audit observed that comprehensive process documentation needs to be established to define roles and responsibilities and ensure sustainability of the financial processes. The management action due on June 30, 2023 includes, documenting processes and defining roles and responsibilities." *Id*.

D. Transmission Cost Allocation

Q. Did you review the Company's alternative transmission allocation between DEP and DEC as discussed in the testimony of Company witness Kathryn S. Taylor?

A. Yes. DEP witness Taylor presented on pp. 17-18 of her testimony an alternative transmission allocation based on DEC and DEP's North Carolina retail transmission demand load ratio share. Witness Taylor stated that the Company was not proposing this alternative but was providing the calculation for the Commission's consideration.

Q. What is your opinion of the Company's alternative?

A. While there is merit to the Company's alternative, and the mechanics appear reasonable at first impression, I recommend a different approach. My proposal does not involve allocating DEP transmission plant costs to DEC or vice versa, but instead focuses on net energy transfers between DEP and DEC. DEC's annual transfers to DEP decreased by ~45% from 2018 and 2019 levels to 2022, while DEP's annual transfers to DEC have increased. Modeling from the 2022 Carbon Plan shows continued increases in transfers from DEP to DEC, due in part to the significantly higher levels of installed and proposed solar photovoltaic generation in DEP, as well as DEP's proximity to the potential location for onshore and offshore wind projects.

My alternative proposal utilizes the non-firm transmission rate from the FERC-approved Joint Open Access Transmission Tariff (OATT) of DEC, Duke Energy Florida, and DEP, which incorporates capital and ongoing O&M costs of the DEC and DEP transmission systems.[39] DEP's alternative allocation only considers a discrete portion of each utility's system and does not consider the O&M costs. The OATT, updated annually and listed on the OASIS website, provides an established calculation for transmission system capital and O&M costs that is transparent and easily verifiable.[40] The Public Staff's recommendation, and the corresponding adjustment, is for retail ratemaking purposes only, and should not be interpreted to imply changes to dispatch or dispatch costs at this time.

DEP's and DEC's 2022 non-firm transmission rates are as follows:

Table 6 DEP's and DEC's 2022 Non-Firm Transmission Rates

	DEP	DEC
Peak	$5.58/MWh	$4.05/MWh
Non-Peak	$2.66/MWh	$1.93/MWh

[39] DEC OATT Transmission Rate Formula Template Using Form 1-Data Utilizing Cost Data for (Historic Years) with Year-End Average Balances Development of Revenue Requirement OATT, p. 3 of 7 (328 of 1170); DEP OATT Transmission Non-Levelized Rate Formula Template Using Form-1 Data Development of Revenue Requirement, p. 3 of 5 (510 of 1170).

[40] This rate was used in the SP5 and SP6 2022 Carbon Plan modeling scenarios recommended by the Public Staff to simulate the reality that utilization of another utility's transmission system should not be at zero cost.

Q. Why do you recommend the use of the non-firm OATT charges?

A. The non-firm rate is appropriate because energy sales (and power flows) between DEP and DEC are occurring via the JDA, which only allows non-firm energy transfers.

The increasing power flows and overall magnitude of MWh generated and transferred from one utility to the other has been a topic of internal Public Staff discussions, as well as potential changes to the JDA. My proposal is an intermediate step in advance of a full merger of DEP and DEC. While not punitive, it would result in an increased cost to DEC customers to gain access to lower cost energy generated in DEP's territory and transferred (wheeled) through DEP's transmission system. Because this proposal encompasses the utilization of DEP's entire transmission system, including costs associated with maintenance and upkeep, it provides a more holistic and encompassing adjustment than one that considers a single set of discrete projects.[41]

Q. What is your proposed adjustment?

A. The detailed mechanics of this proposal are straightforward. Using the calendar year 2022 hourly power flows (MWh) from DEC to DEP and from DEP to DEC for each hour, DEC's power flows are subtracted from DEP's, resulting in a net power flow for each hour. Next, the on- and off-peak hours

[41] DEP witness Taylor's approach focused solely on the Red Zone Expansion Plan (RZEP) projects.

are calculated and multiplied by the appropriate OATT rate for each hour of energy transfer by utility using DEP's rate, given that DEP was net long in energy transfers. Finally, all of the $/MWh of on- and off-peak rates are summed. The segmented table below shows net power flows by hour ending 0800 (8am) through 1700 (5pm). The net power flows simulate solar generation at peak hours, which approximates the behavior seen in the 2022 Carbon Plan results and coincides with the amount of DEP solar generation compared to DEC.

Table 7 DEP to DEC Net Transfers per Hour

2022									
DEP to DEC Net Transfers per Hour									
MWh									
8	9	10	11	12	13	14	15	16	17
148,941	237,906	334,802	411,512	466,612	492,634	493,521	473,781	431,134	335,882

This method results in DEP receiving approximately $29M (system) annual non-firm retail transmission revenues from DEC. The NC retail adjustment for DEP is approximately $20M. I have provided this calculation to the Public Staff Accounting Panel.

After discussions with Duke, I believe this proposal should not impact the JDA, impact the way that the OATT rates are calculated, run afoul of the JDA provisions, interfere with FERC rules and ratemaking, or impact the Public Service Commission of South Carolina's jurisdiction.

This proposal should help mitigate further exacerbation of the rate disparity between DEC and DEP by balancing system costs with system benefits from the perspective of NC retail ratepayers.[42] [43]

IV. MYRP Recommendations and Findings

A. Review of MYRP

Q. Please summarize your review of the Company's proposed MYRP.

A. The Public Staff reviewed the Company's initial and supplemental February filings and updates, initiated multiple sets of discovery, and participated in multiple meetings with the Company on the MYRP. To aid in our review of certain aspects of the transmission MYRP, the Public Staff retained GDS and Associates, Inc., to augment internal technical staff. GDS reviewed the Company's power flow analysis, which is often used to justify the need for transmission-related projects. The findings and recommendations of GDS's investigation are contained in the testimony of GDS witness Chiles on behalf of the Public Staff. I have incorporated his recommendations and provided proposed adjustments to the Public Staff Accounting Panel.

[42] Order Adopting Initial Carbon Plan and Providing Direction for Future Planning, p 128, issued in Docket No. E-100, Sub 179 on December 30, 2022.

[43] This proposal would not only resolve the Commission's Carbon Plan Order and future resource planning, but also addresses current system conditions and equitably compensates DEP ratepayers for use of DEP's transmission system.

Q. Please provide your general impressions of DEP's MYRP.

A. DEP's proposal has several broad issues that could impede successful implementation of the MYRP to the detriment of ratepayers, including inadequate staffing, lack of Company-wide project optimization, inability to adapt to changing conditions given the timing of the MYRP projects, and the likelihood of costs attributable to projects not currently in the plan.

If the Company has proposed to complete a portfolio of programs on an unrealistic timeline without acquiring and maintaining adequate staffing levels or material procurement over the three-year planning period, there could be a significant risk that ratepayers will pay for projects that will not be completed or will have to pay even more to complete planned projects due to higher labor costs and project management inefficiencies. Mitigating this risk is not as simple as asserting that if the Company spends less than forecasted, the earnings mechanism will result in refunds.

A review of the full MYRP also reveals that the Company did not "globally" optimize project spend across all of the business groups. While there was project optimization within each business group (e.g., transmission, distribution, nuclear, fossil, renewables, etc.), the Company did not compare projects from one business group to projects from another in an effort to truly maximize the benefits of the total spend requested in this case.

Lastly, the degree of uncertainty must be considered when reviewing the Company's MYRP. When unforeseen events alter the timelines of projects due to unanticipated equipment failures or require the Company to replace entire programs to meet changing NERC standards, or to respond to events like the substation attacks in Moore County, the MYRP proposed today will likely be very different from the one proposed in three years. Projects in the MYRP filed in October have already been altered or replaced in just the last five months.

Q. Please comment on the Company's initial testimony and the Public Staff's review of the MYRP proposal.

A. This application is the Company's first MYRP filing, as well as the Public Staff's first review of an electric utility MYRP filing. As a result, issues were bound to arise; however, the Company's initial filing and supporting work papers created significant issues for the Public Staff. These issues center around incomplete project support, and project support documents not aligning with the Company's workpapers used to calculate rates, notably Taylor Exhibit 4, Workpaper 5. After multiple meetings between the Public Staff and the Company to identify the deficiencies and inconsistencies, the overall issue of incomplete or missing documentation was mostly resolved, but not before the Public Staff lost about two weeks of productivity and multiple weeks in which to conduct discovery. Then, in late November, the Public Staff submitted multiple discovery requests to reconcile the Company's MYRP application with correct and complete project documentation.

Q. Please describe the communication between the Company and the Public Staff during your review of the October 6 initial filing and reconciliation discovery.

A. Overall, the Company was receptive and incorporated significant portions of the Public Staff's feedback regarding its requests for reconciliation discovery.

Q. During or even after the reconciliation discovery process for the MYRP, were there any other larger issues the Public Staff identified or discussed with the Company?

A. During our review of the initial filing and while evaluating the reconciliation discovery of MYRP projects, it became clear that the project estimates were relatively old and likely outdated. For example, certain projects had estimates that were multiple years old, and initial funding requests (project funding approvals or equivalent) were completed in spring of 2022, nearly 6 months before the filing of the MYRP application. I acknowledge that it takes time to compile, vet, and create project authorization accounting schedules for over $4B in capital spend over three years, but risks of out-of-date project estimates are a significant concern, especially given 2022 inflation and supply chain constraints. The fruits of these efforts of the Public Staff and the Company can be found in the Company's February 2023 update filing. Now that Duke is aware of these issues, the Public Staff hopes to avoid the need for reconciliation data requests and large-scale supplemental MYRP updates in future rate cases, enabling the Public Staff to use the full discovery period to audit accurate information.

Q. Please summarize the Company's February 2023 update filing.

A. As stated above, one purpose of the February 2023 update filing was to address the Public Staff's concerns with stale estimates. During the discovery process for the original filing, the Company self-identified select projects that it decided to remove from the filed MYRP. Thus, a mid-rate case revision to the MYRP projects (inclusive of project needs, timing, and costs) was appropriate and mitigated some of the Public Staff's concerns; however, a wholesale substitution of the projects in the original application would have been unreasonable.

The graphs below illustrate the historic rate case spend the Company seeks for recovery, as well the MYRP (February update) and MRYP capital spend by category and by Rate Year.

Figure 9 DEP Capital Closed to Plant 6/20 – 11/22

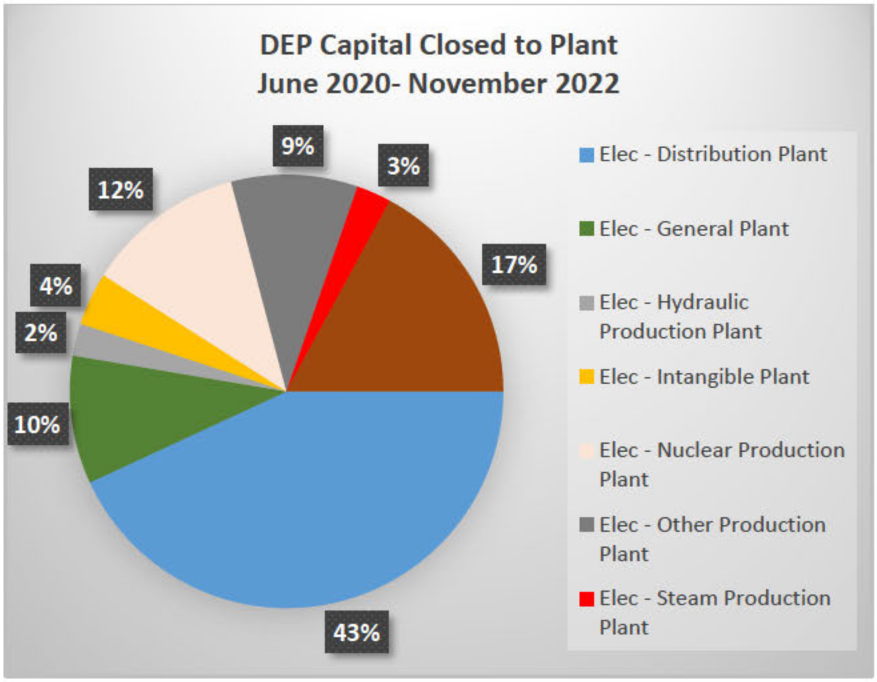


Figure 10 DEP MYRP Capital Spend Projection

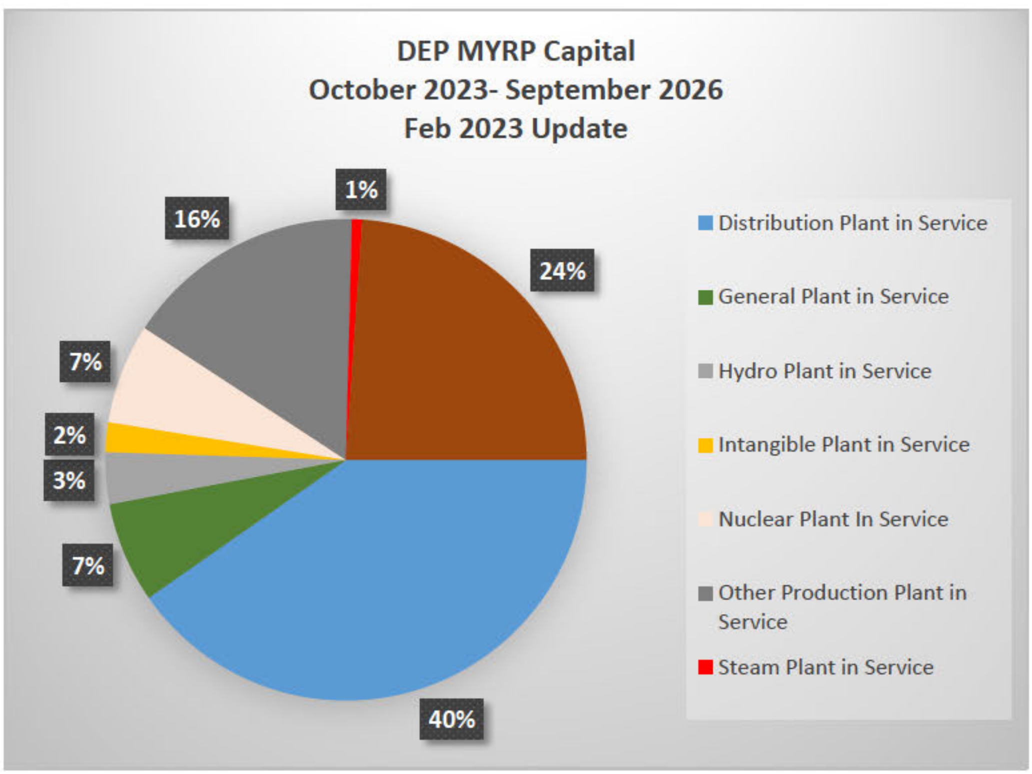


Figure 11 DEP MYRP Capital Spend by Rate Year

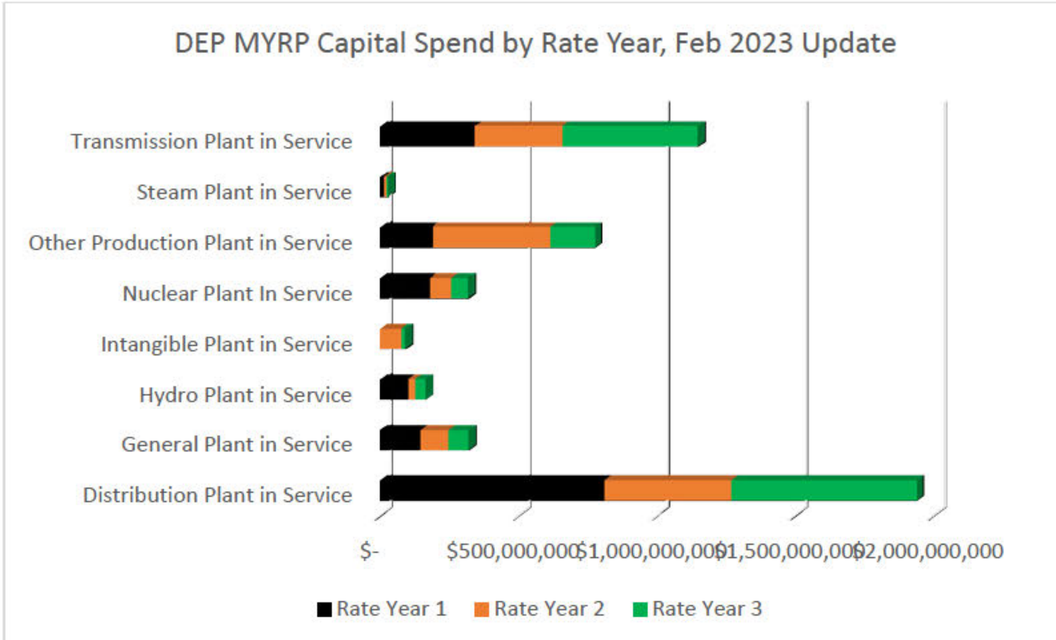
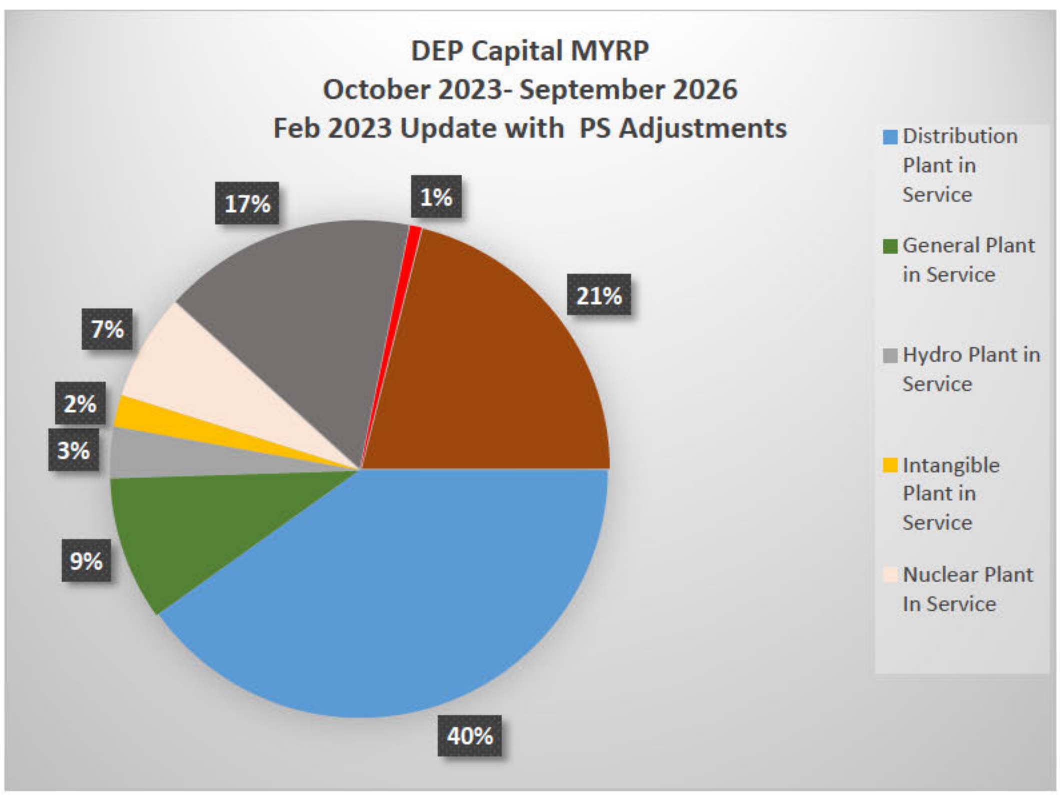


Figure 12 DEP MYRP Capital Spend with Public Staff Adjustments



The proposed MYRP project spend, which is not the Company's total expected capital spend during the MYRP period, is close to historic spend levels by percentage and category except for a few, albeit important, differences. Hydro plant in service is elevated in the MYRP compared to the Base Case because of the Blewett Falls TST. Other Production plant in service will also be elevated in the MYRP given the increase of battery storage projects and miscellaneous solar projects projected to go in service during each respective Rate Year.

Q. How does the review of a traditional rate case compare to the review of both a historic and MYRP rate case?

A. The MYRP process, at a minimum, doubled if not tripled the amount of time required to audit and review compared to a traditional rate case. Auditing the MYRP elements of the case reduced our total time to work on the historic part of the case, and vice versa. Adding the review of DEC's MYRP on top of the DEP filing exacerbated the challenges.

B. Staffing

Q. Please discuss your concerns with DEP's proposed MYRP.

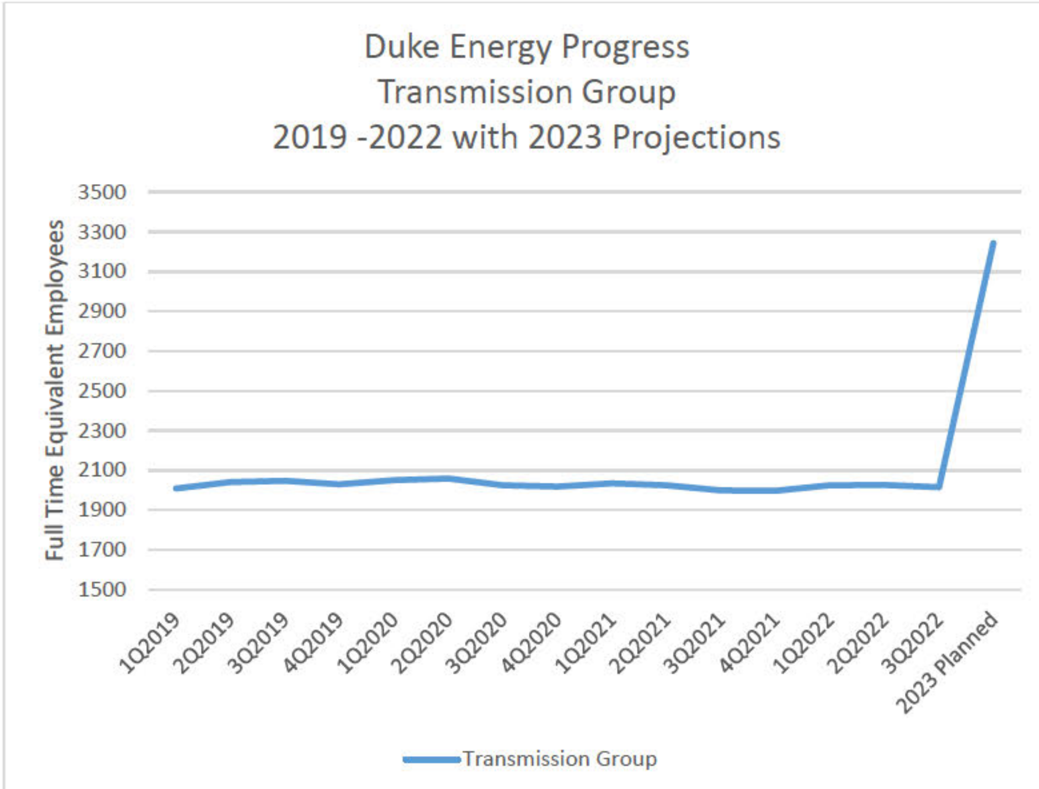
A. My greatest concern is the Company's ability to meet necessary staffing levels to complete its proposed MYRP projects. In order to complete projects, sufficient labor resources (as well as the necessary equipment) are required to complete the work. The labor resources can come from internal or external labor, as there may be cost premiums for utilization of external labor and meeting project timelines.

My concern regarding staffing arose from my review of the Company's historic staffing as well as 2023 staffing projections.[44] I anticipated increases in staffing for the T&D work groups given the number of T&D projects in the MYRP. Responses to discovery raised additional concerns about the negative trends in reliability and availability of the fossil fleet, which I discussed earlier.

Below is the Company's most recent internal staffing level for the Transmission Group, followed by its 2023 projection. Overall, Transmission has around 2000 employees currently, but the Company is anticipating a precipitous increase of ~1000 more internal employees in a single year. Even in isolation, it seems like a challenge to internally hire this many employees in such a short time period.

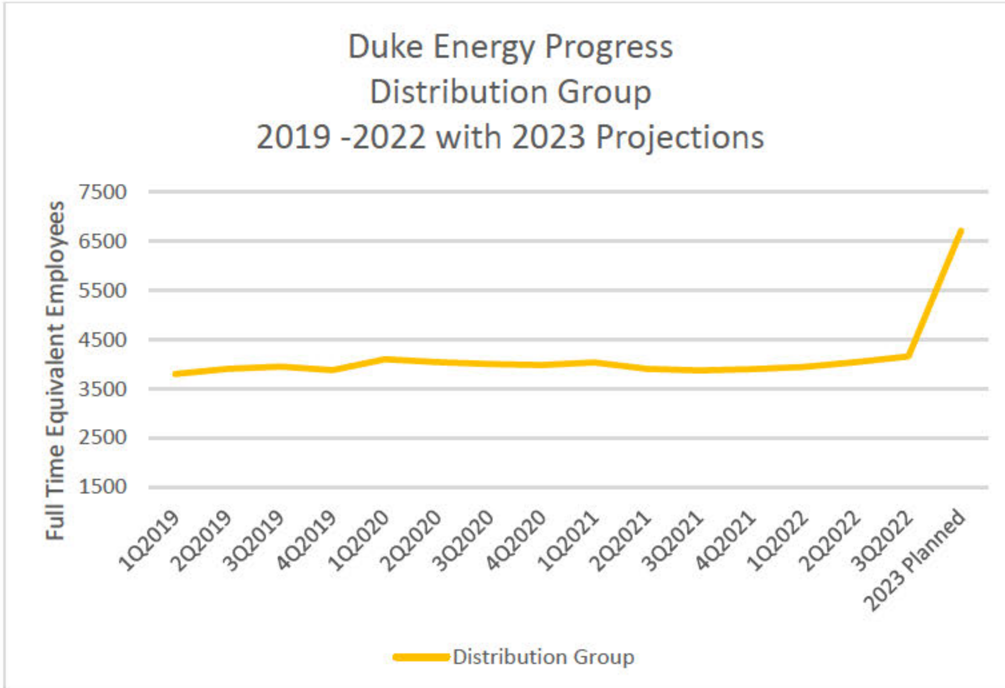
[44] Reference Company Response to PS DR 6. Upon further review of the discovery responses in PS DR 6, it appears that the Company reported certain business groups at a corporate or even a DEBS/DEC/DEP level, while other categories are at only the DEP level.

Figure 13 DEP Transmission Group Staffing



Distribution staffing follows a similar trend to transmission. Historically, the Company has around 3,800-4,000 internal distribution employees, with some recent additions in 2022. However, similar to Transmission, the Company expects to increase internal staffing by over 50% in the coming year. This magnitude of change is staggering and poses a risk that the Company may be unable to complete the MYRP capital work in addition to normal, business-as-usual work (i.e., projects not listed in the MYRP) on time and on budget. If the Company is not able to meet its forecasts, the question arises as to whether it is reasonable for ratepayers to bear the cost premiums for external labor.

Figure 14 DEP Distribution Group Staffing



Another concern relates to historic and projected staffing for other business groups, some of which involve MYRP projects and others that pertain to basic, ongoing utility services. Part of my review in both the traditional general rate case and the MYRP involved consideration of the Company's plan for labor staffing to complete these MYRP projects, and the execution or cost risk to ratepayers for completing the Company's proposed projects. The graphs below show forecasted labor for other business groups (exclusive of transmission and distribution).

Figure 15 DEP Nuclear Group Staffing

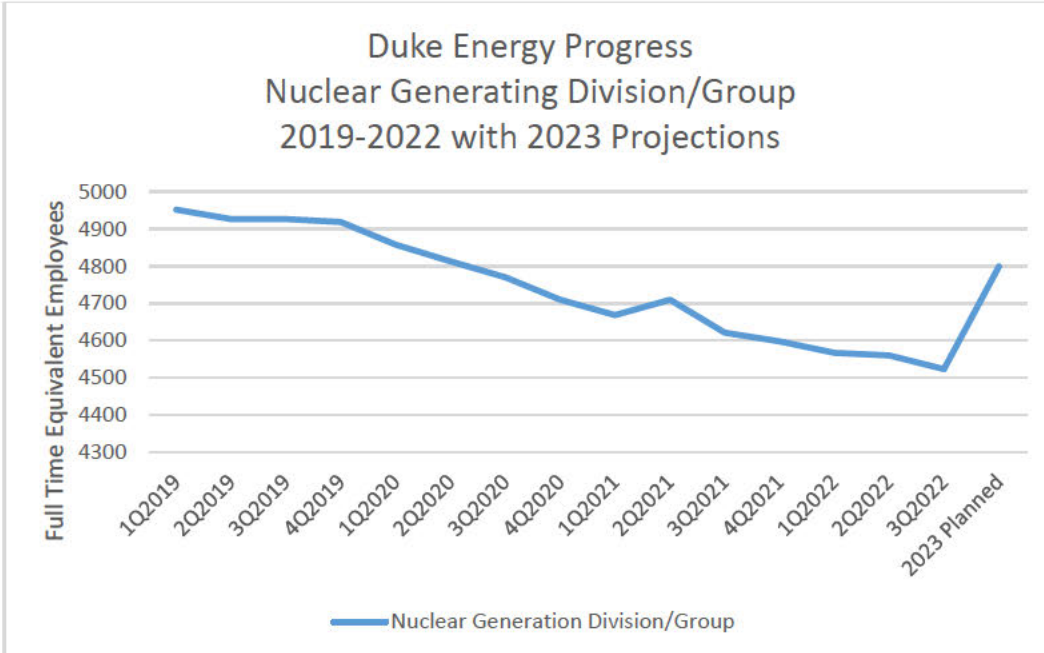


Figure 16 DEP RRE, Renewables and Traditional Generations Groups Staffing

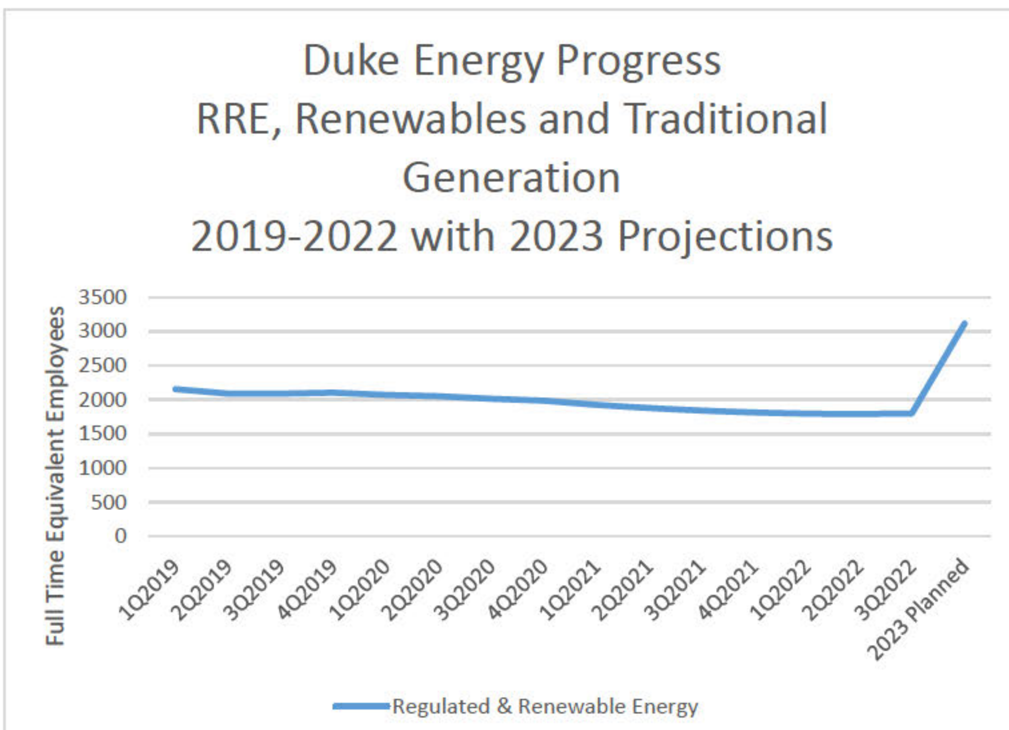
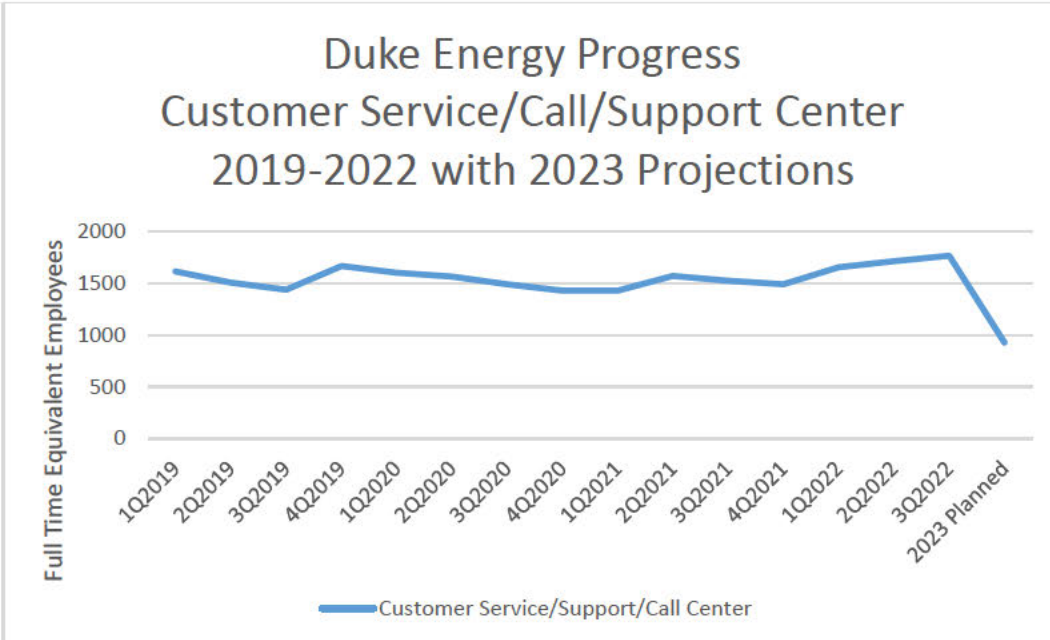


Figure 17 DEP Customer Service Group Staffing



I issued multiple discovery requests, as well as participated in meetings with the Company, to understand how the Company plans to augment its current labor force to complete the MYRP projects. Overall, I found their responses regarding the increased staffing of the transmission business group to be the most uninformative. From my view, the Company does not have a plan to increase staffing for planned MYRP work while continuing to perform traditional work other than to rely on the outside market.

Q. Please address the overall capital spend in the MYRP.

A. Projects completed in the Base Case (June 2020 through November 2022) resulted in an average capital spend of $112M a month, whereas the

Company's MYRP capital project plan projects to spend ~$134M a month.[45] Notably, the Company's MYRP project plan does not include all the work expected to take place during the MYRP period. The Company's proposed MYRP capital projects plus non-MYRP capital-related work total $225M per month (compared to the Base Case $112M, discussed previously).[46] Below are several graphs and a table, the first showing the Company's base case capital spend and the second showing the Company's MYRP capital spend by business group. The chart that follows lists the Company's historical capital spend, projected MYRP capital spend, and projected total projected spend (MYRP and non-MYRP spend) all by business group. Comparing the historic spend amounts per business group, inclusive of emergent or opportunity work that typically arises, to the adjusted capital project work that is likely to take place over the next three years, illustrates how the total spend percentage by category shifts.[47]

[45] The Public Staff is still auditing items closed to plant post-November 2022.

[46] This spend does not reflect any removal of projects from the historic rate case or the MYRP. These values are based on the Company's ask for rate recovery and any additional items that were self-identified by the Company in discovery.

[47] The Company reported the spend per groups differently than how costs were reported in the MYRP. However, the general spend of Distribution and Transmission should be the same between the Base Case and expected capital spend.

Figure 18 DEP Base Case Closed to Plant

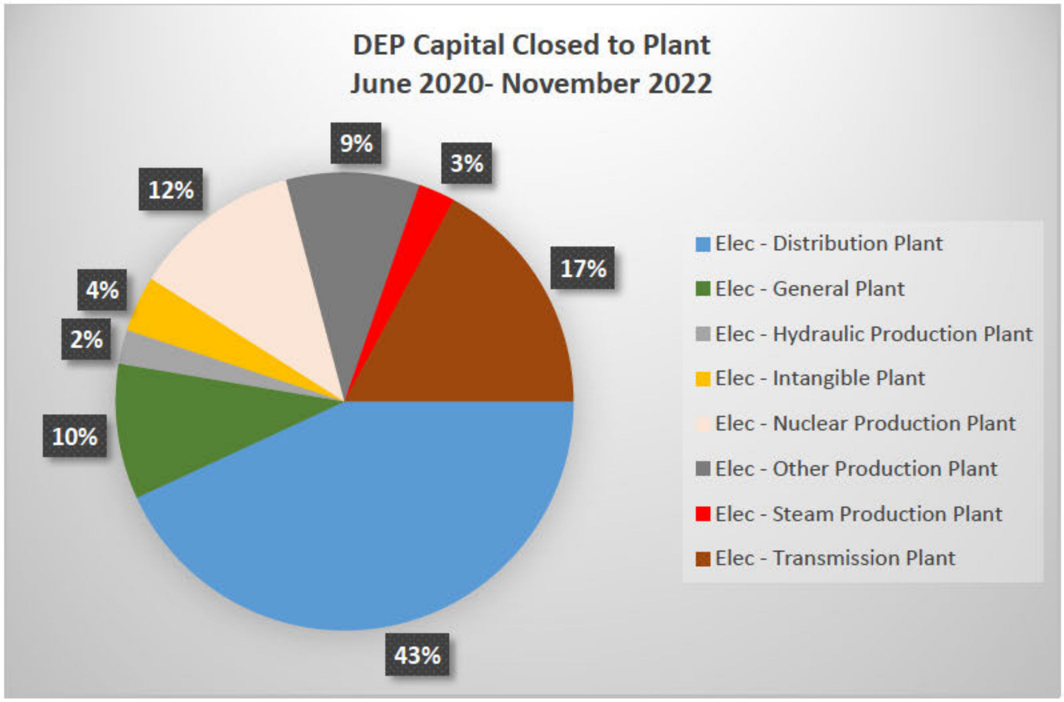
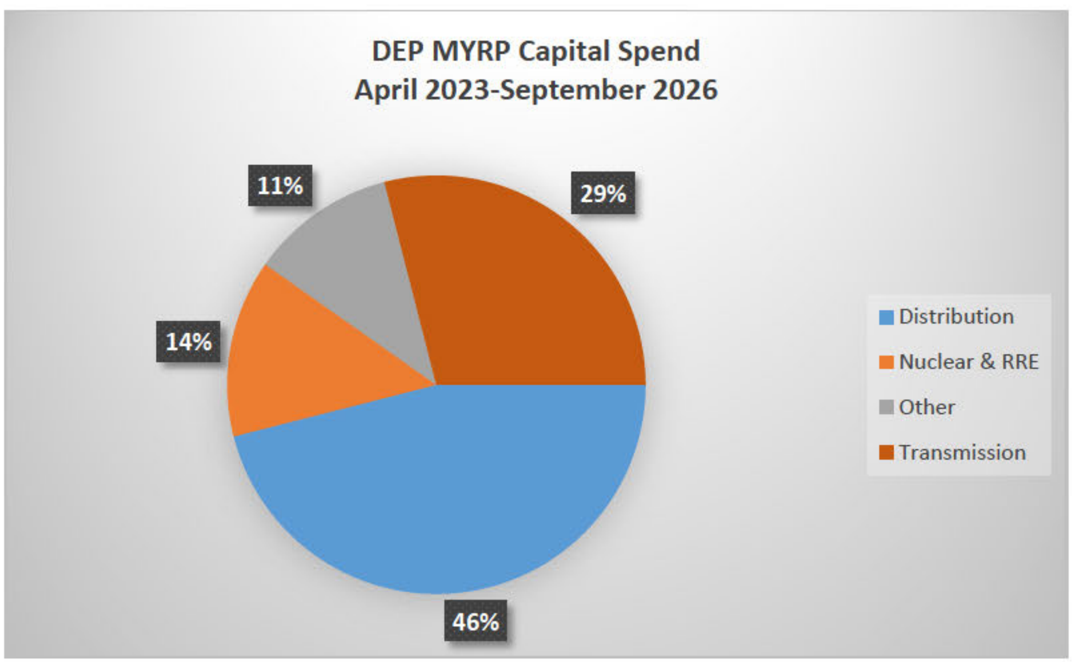
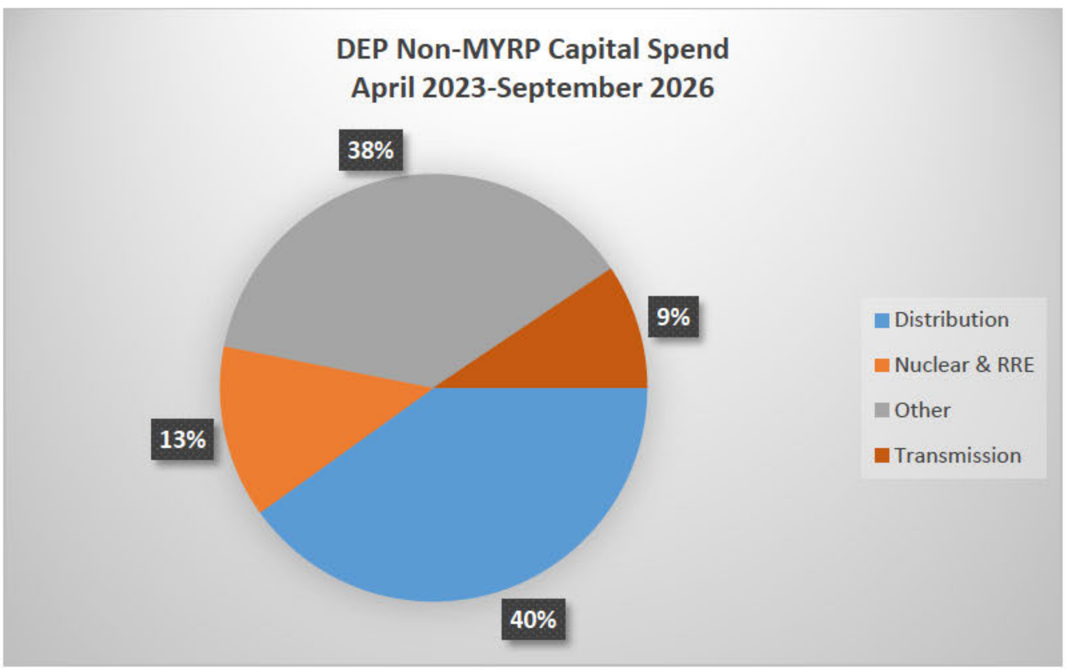


Figure 19 DEP MYRP Capital Spend



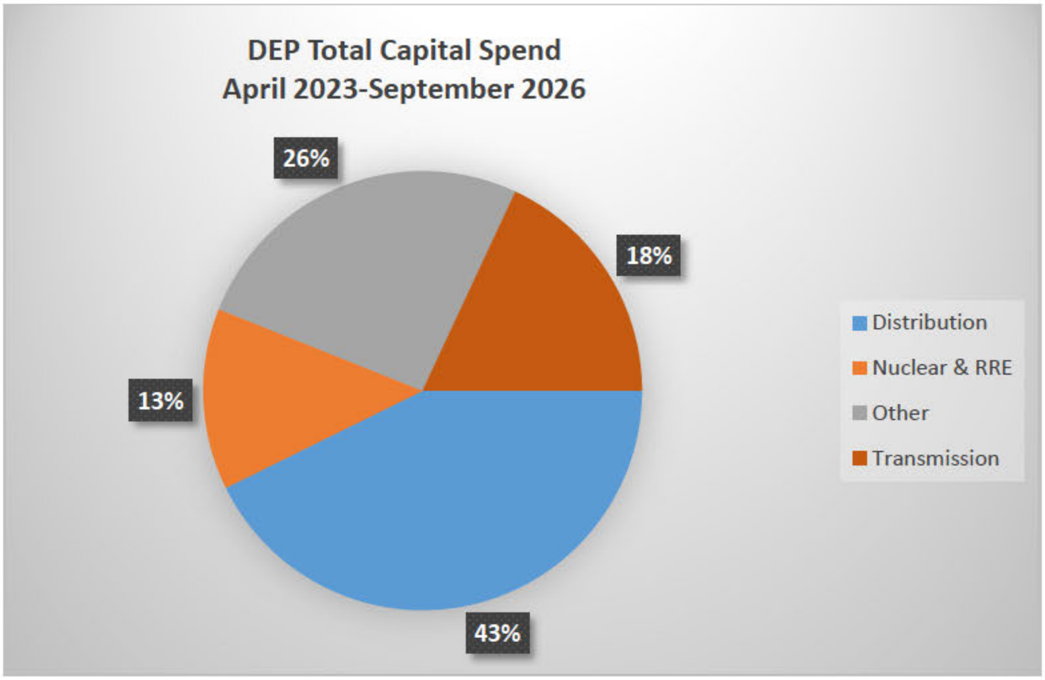
Some of the cost shifts between the historic case and the MYRP may be misleading without proper context. For example, the Hydraulic Production Plant increase is in part due to a single and unique project at Blewett Hydroelectric Plant, discussed in more detail in Public Staff witness Thomas's testimony. Witness Thomas also reviewed the new solar additions and battery storage projects (listed as Other Production Plant), which contribute to the cost increase in that category. However, the Company also plans to make capital expenditures that are not in the MYRP, as shown in the graph below.

Figure 20 DEP Non-MYRP Capital Spend



Listed below is the total (MYRP and non-MYRP) capital spend by percent per category over the MYRP horizon.

Figure 21 DEP MYRP and Non-MYRP Total Capital Spend



What these four graphs do not show is the total overall monetary capital amount of MYRP and non-MYRP projects from April 2023 through September 2026.[48] Table 9 Overall Capital Spend - MYRP and Non-MYRP shows the monetary amount.

Table 8 Overall Capital Spend - MYRP and Non-MYRP

	MYRP Capex	**Non-MYRP Capex**	Total Capital
Distribution	$1,838 M	$2,033 M	$ 3,871 M
Nuclear & RRE	$549 M	$662 M	$ 1,210 M
Other	$449 M	$1,899 M	$2,348 M
Transmission	$1,158 M	$478 M	$1,636 M
Total	$3,994 M	$5,071 M	**$9,065 M**

[48] See Company response to PS DR 232-3&4.

The Company is expecting to spend nearly $9B in capital over a 42-month period. To put this in perspective, the Company is seeking cost recovery of ~$3B for capital projects closed to plant from June 2020 through November 2022 (30 months). The Company's future capital spend is three times greater than the total amount sought for the Base Case recovery in this general rate case.

I reviewed the year over year change to the MYRP capital projects as a function of total capital spend, inclusive of labor costs, as shown below in the Table 11 Total CapEx Budget. The table shows the MYRP capital project year over year change (Rate Year over Rate Year change) only and does not include the additional project work (non-MYRP related work) the Company expects.

Table 9 Total CapEx Budget

DEP Total Capex Budget (in millions)			
	RY 1	RY 2	RY 3
Distribution	1,649	1,114	1,108
Nuclear & RRE	502	324	384
Other	546	807	996
Transmission	782	429	425
Total	3,479	2,674	2,913

Public Staff Data Request 155 asked the Company to explain how it evaluated labor resource constraints as part of its MYRP proposal, and to provide supporting analysis and data. We met with the Company to discuss this discovery request shortly after it was submitted to the Company and prior to the Company's response. I have attached the questions and responses below. Many of the questions request the same information for each business unit as it is reasonable that staffing requirements during a routine outage at a power plant are much different than for transmission work.

Figure 22 Response to Data Request 150-1

Request:

1. Please identify key staffing and labor metrics the Company typically uses to evaluate work projects, work project completion, and timeline management.

Response:

The Transmission function evaluates resourcing strategies on an ongoing basis as work progresses and employs strategies like shifting resources to areas of need and flexing work schedules. For Project Management and Engineering, resources are identified and assigned on a project-by-project basis. When internal resources are not available to meet the time constraints of the project, external resources are identified. Likewise, for the construction phase of the projects, internal construction resources are assigned when they are available and external suppliers are utilized to supplement those resources as needed. More specifically, during project development, resource forecasting (largely for craft/line labor) is performed by taking into consideration the identified work scopes, estimated durations and operational considerations to determine the number of crew resources needed to execute the plan. The resulting resource forecast is compared to current headcount to determine what supplemental external labor is needed to support the forecasted resource need.

Concerning "timeline management," a practice the Transmission function utilizes at the conceptual design stage is reserving/ordering certain materials from suppliers (i.e., breakers, transformers, regulators, relay panels, control houses) in the Company's internal work management systems. In some cases, the Company can reserve manufacturing "slots" with suppliers for project components. Other materials are ordered during the detailed design stage, or reserved from the Company's inventory.

Further, the transmission function creates a more detailed "look ahead" workplan at 6-month intervals that considers outage constraints, summer and winter peaks, and generation outages.

Figure 23 Response to Data Request 150-2

Request:

2. For Rate Years 1 through 3, list each of the Company's key staffing and labor metrics, for each Rate Year, along with the respective scores/requirements of each.
   a. If the Company did not perform such an analysis, please explain why not.

Response:

Please refer to the Company's response to PSDR 155-1. The Company has not performed the analysis requested in PSDR 155-2 due to the nature of the varying types of projects, resource needs, and operational conditions impacting timing of construction; but, for the reasons explained in the response to PSDR 155-1 and throughout these responses, is confident that the projects proposed for each Rate Year will be completed.

Figure 24 Response to Data Request 150-3

Request:

3. For Rate Years 1 through 3, please provide the following information per Rate Year as deemed necessary to complete all the Company's proposed work:
   a. Total hours of DEP employee craft and equivalent full-time employees.
   b. Total number of DEP trucks.
   c. List of specialized equipment/vehicles.
   d. Total hours of external vendor employee craft and equivalent full-time employees.
   e. Total number of external vendor trucks.
   f. Total hours of DEP project management and equivalent full-time employees.
   g. Total hours of vendor project management and equivalent full-time employees.
   h. Total hours of DEP engineers and equivalent full-time employees.
   i. Total hours of vendor engineers and equivalent full-time employees.
   j. Total aggregate hours for all work and equivalent full-time employees:
      i. DEP employees
      ii. Vendors
   k. List DEC resources used in the staffing and the equivalent full-time employees.
      i. If other DEP affiliate resources are required or expected to be utilized, please list those as well by affiliate.

Response:

Please refer to the Company's response to PSDR 155-1.

Figure 25 Response to Data Request 150-4

Request:

4. For equipment that either (1) takes 6 months or longer to procure and deliver or (2) is a single piece of equipment that is >$150k, identify the total amount of equipment and labor costs by Rate Year.

Response:

Please refer to DEP's response to PSDR 155-1. The dynamic nature of the procurement and project development processes utilized by DEP (which is described in response to PSDR 155-1) renders this data request premature since final costs for individual pieces of equipment and the procurement timelines are not certain until equipment is actually ordered – which has not occurred in the vast majority of cases with regard to MYRP projects in DEP's MYRP.

Figure 26 Response to Data Request 150-14

Request:

14. By Rate Year, list the Company's expected percentage of completion of each MYRP project and their respective costs.
    a. Provide supporting analysis.
    b. List the number of projects and project costs that are assumed to have greater than 90% certainty of being completed in the respective rate year.
    c. List the number of projects and project costs that are assumed to have 81% to 90% certainty of being completed in the respective rate year.
    d. List the number of projects and project costs that are assumed to have 71% to 80% certainty of being completed in the respective rate year.
    e. List the number of projects and project costs that are assumed to have 70% or less certainty of being completed in the respective rate year.

Response:

Please see DEP's responses to PSDR 155-1 and 155-4.

The Company is confident that the projects within each Rate Year can be completed. However, the Company further observes that the Commission itself has acknowledged the need for the Company to exercise discretion in implementing the MYRP in order to benefit customers. Therefore, it is likely that a variety of factors (including factors outside of the control of the Company) will require the Company to modify or adjust certain MYRP projects for the benefit for customers. Please refer to "Maley Direct Exhibit 2 - MYRP Distribution Project Detail" for the estimated cost and project completion date for transmission projects included in DEP's MYRP.

As shown in the responses above, the Company has yet to develop any staffing or labor metrics to assist in developing the MYRP work projects, determining work project completions, and timelines. In addition, it has not identified any equipment necessary to carry out its MYRP that takes longer than six months to procure or costs over $150,000, it has not developed projections of the staffing or equipment that will be needed and has not assessed the risks for MYRP projects that fail to achieve projected in-service dates. Nevertheless, the Company denotes portions of these discovery requests as premature and expresses confidence that it will complete the projects, pointing to the Commission's rules allowing the Company to modify or adjust projects as it deems necessary.

I do not have the same confidence as the Company that the projects in each Rate Year can be completed. I understand that the MYRP is a forecast and projections change over time. Nonetheless, the Company appears not to have even begun some of the actions I believe are necessary to implement these projects over the next three years. This lack of information prevents the Public Staff and other intervenors from performing their own analysis of the projects and providing input to the Commission. An MYRP should not be a blank check for the Company to do as it determines without any oversight. Of course, when the projects are put into rate base, the Commission will consider their reasonableness and prudence. But the Company should have enough information for analysis of whether there is a **<u>need</u>** for the project and whether the Company has the **<u>ability</u>** to complete it, including the costs, staffing, and timelines, as well as a risk analysis.

In determining the likelihood of completion of the MYRP projects, I used the information available to me in this case. I also requested any analysis the Company used to evaluate the likelihood of project completion. As indicated in the response to PS DR 155-2 above, no analysis was completed.[49]

I followed up with additional discovery, PS DR 232, once again trying to understand the Company's plan for staffing to implement the MYRP and gain insight into the non-MYRP work and how the Company is managing both aspects of utility planning. PS DR 232 is contained in Exhibit 1. Key takeaways from the response are:

- Distribution has identified a gap in resources ~2% shortfall, based on $/employee metric.
- Transmission has not begun a staffing and does not appear to have one.
- Transmission planning is "typically multiyear, complex, involving multiple disciplines (electrical, civil, mechanical) and therefore resource needs are determined by each individual scope of work as compared to the Distribution method that utilizes the target budget numbers and average cost per resource."[50]

---

[49] I also asked for identification of material items that may have long lead times that would carry a higher risk of project impacts (scope, timing, and costs), but the Company stated that my request was premature (see response to PS DR 155-4 as well as other discovery responses in PS DR 155) even though the Company does not dispute that the industry is experiencing supply chain constraints.

[50] See Company response to PS DR 232-6.

- Transmission appears to be dependent on Master Service Agreements and external vendors. This further exposes the Company (and ratepayers) to employee staffing constraints that are outside of DEP's control, as well as potential higher costs of external staffing.

Given the Company's responses regarding MYRP transmission and distribution projects as well as non-MYRP related work, I do not believe that the Company can execute and complete its entire proposal within the three-year time frame requested or within its estimated budget. Thus, approval of the Company's proposed MYRP would place a considerable amount of risk on ratepayers.

C. Risk and Cost Optimization across Business Groups and Flexibility

My second and third concern can be grouped together. I was unable to identify how the Company determined the total capital spend for each business group (Distribution, Transmission, Steam, etc.) per Rate Year based on discovery in this case. I was, however, generally able to identify how projects within a business group were established. For example, I reviewed whether the Company compared a project in one business group (Steam Plant) to a distribution project, or to a distribution program that includes many projects. As I have discussed earlier in my testimony, if one uses only SAIDI as the reliability metric for transmission and distribution and WEAF and WEOUF as the reliability metrics for fossil generating units, the

Company's projected spending in the MYRP appears to be skewed toward improving SAIDI, a reliability metric that is already improving. This situation is further complicated given the cost allocation of investments and the direct monetary impact to specific customer classes.[51]

PS DR 137-1, Supplemental Response, identified how the Company determines the bottom-up cost building for purposes of Company budgeting. I attached the entire discovery response as an exhibit and include a portion below.

[51] For example, only ~62% of the costs of a capital reliability improvement at a generating plant would be assigned to NC Retail, while all the costs of a distribution project in North Carolina would be assigned to NC Retail. I am not proposing a change to the cost allocation or cost of service, merely highlighting that the costs of certain projects are allocated to customers differently. There is a discrete difference in how a NC Retail customer's final bill, by function of the revenue requirement and cost allocation factor, would be impacted by different capital costs.

Figure 27 Supplemental Response to Data Request 137-1

Request:

1. Please provide a general narrative of the Company's five-year capital plan. The narrative should include, but not be limited to, the following topics: date of proposal; date of approval; why changes occurred from the proposal to the approval stages; how the Company evaluates spend per business unit; how the Company prioritizes capital projects in one business unit versus another; how Duke Energy Corporate interfaces in project review and the approval process; general annual timeline of the overall process; and how the five-year plan informs the annual capital spend in the most current calendar year in which it is in effect.

Supplemental Response (Feb. 15, 2023):

The Company's formal capital planning process occurs within an annual cycle. An annual capital budget is set for the enterprise and each jurisdiction based on information received from the various functions (i.e., transmission, distribution, nuclear, etc.). During the Spring, capital targets are set for each jurisdiction and function that recognize regulatory commitments and requirements, as well as operational needs, while also optimizing cash flow and balance sheet needs. For example, capital projects approved as part of a MYRP would be deemed regulatory requirements and be factored into the capital target for a particular jurisdiction/function. These targets are developed based on input received from each function within each jurisdiction.

Based on my review of the MYRP, discovery, and substitution of projects, it appears that each business unit was assigned a narrow range of total capital spend and maximized their individual portfolios without immediate coordination and re-optimization with other business groups.

D. Total Spending and Bill Impacts

Q. Did you review the Company's CapEx spend from prior years and compare it to the MYRP total spending?

A. Yes, I reviewed the Company's budgeted (B) and actual (A) CapEx spend from 2019 through 2022. The following dollar amounts are in millions.[52]

[52] See Company response to PS DR 232-1&2. 20xxA = Actual Spend and 20xxB= Budgeted

Table 10 Budgeted & Actual CapEx Spend 2019 - 2022

Duke Energy Progress - 2019	2019A	2019B
Nuclear & RRE	846	794
Transmission	283	225
Distribution	683	608
Other*	151	223
Total Capital	**1,962**	**1,850**
Duke Energy Progress - 2020	**2020A**	**2020B**
Nuclear & RRE	460	558
Transmission	269	268
Distribution	636	699
Other*	142	181
Total Capital	**1,507**	**1,706**
Duke Energy Progress - 2021	**2021A**	**2021B**
Nuclear & RRE	541	533
Transmission	270	289
Distribution	634	652
Other*	186	218
Total Capital	**1,631**	**1,692**
Duke Energy Progress - 2022	**2022A**	**2022B**
Nuclear & RRE	654	778
Transmission	365	392
Distribution	947	925
Other*	184	313
Total Capital	**2,150**	**2,408**

The Company's actual and budgeted capital spend show variance year to year with an ~5% actual amount spent less than budgeted. Given historic variances, I am not certain the Company can stay on track with its targeted MYRP spend, notwithstanding the potential labor resource constraints or other issues already discussed.

Another observation is the magnitude of the historic CapEx compared to the next three years of projected costs. The table below shows the Company's expected Total CapEx of MYRP and non-MYRP projects by Rate Year.

Table 11 Total CapEx Budget

Total Capex Budget (in millions)			
	RY 1	RY 2	RY 3
Distribution	1,649	1,114	1,108
Nuclear & RRE	502	324	384
Other	546	807	996
Transmission	782	429	425
Total	3,479	2,674	2,913

From 2020 to 2022, the Company spent ~$5B in total capital compared to 2023-2026 (Rate Year 1 through 3) ~$9B. This further highlights the magnitude and potential rate impacts of the MYRP and the next general rate case.

Q. Did you review the total monetary impact of the Company's proposed MYRP and non-MYRP capital spend over the next three years?

A. Yes. The short-term changes to rates are well noted in the Company's application as well as more recent annual fuel riders of all the electric utilities under the NCUC's purview. I have also noted that the Company intends to book non-MYRP costs to be recovered in its next rate case that may equal or exceed the costs included in the MYRP. It is shocking that maintaining or improving the overall reliability of the Company's entire electric system requires nearly a $9 billion dollar capital project spend by the end of Rate Year 3 (September 2026).[53] Further, it is not clear how much of the Company's projected non-MYRP capital spend relates to the future energy and capacity resources identified through resource planning and whether a larger CapEx spend in 2027 through 2030 is looming to further increase rates.

Q. Did you quantify the bill impacts or the change in the revenue requirement?

A. I did not perform a bill impact analysis but did evaluate the potential impact on the total revenue requirement. Using the Company's exhibits and workpapers, I created proxy projects for each Rate Year and for each of the four general types of MYRP project categories (Nuclear & RRE, Distribution, Other, and Transmission). My high-level estimates indicate that the overall **revenue requirement** at the end of Rate Year 3 will be ~$4.9B, compared to the base revenue at present rates of ~$3.4B (as listed in the DEP customer notice), representing a potential 30% increase in base rates in just three years, excluding any impacts from annual riders (e.g., fuel, storm securitization, etc.). Given my estimate of the revenue impact of the Company's MYRP and non-MRYP spend over the next three years, current rates will approximately double between now and the end of the Company's next rate case. While the prudency of those investments will be reviewed in

[53] See Company response to PS DR 232-3 and 4.

the next general rate case, the Commission should be made aware of the future impacts of the Company's entire projected three-year plan, and not only the MYRP.

E. Contingency Adjustment

Q. Please describe your contingency adjustment.

A. Generally, project contingency is an increase in project funding, above the base estimate, to cover uncertainty and risk. It is important to ensure that there is only a single contingency amount incorporated in the final estimate or contingency costs could be added to the individual stages of a project, ultimately overinflating the overall project cost. This inflated cost could be compounded when a final contingency is added near the end of the project estimate. Adding project contingency only at the end of the calculation of a project cost estimate is a method to prevent double counting of project contingency and pancaking of duplicative costs. For example, Public Staff witness Thomas found that the Blewett Falls TST project included excess contingency, and the removal of the excess contingency was reflected in his adjustment.

In considering the appropriate amount of contingency, it is important to consider the class of the project cost estimate. There are five different levels of class estimates with ranging variances in the degree to which the project has been defined, how far the project has progressed in being developed (screening, study, budgeting, or actively being built), the methodology used to create the estimate, the expected accuracy of the estimate, and how much effort has been put into preparation of the estimate.[54] Also, as more information is known about the project, or as the project proceeds, project contingencies can, in theory, be reduced as risk and uncertainty surrounding the overall project cost time schedule lessen. DEP has provided Class 4 and Class 5 cost estimates for its MYRP projects, meaning that the project has only been defined from 0% to 15%, the estimate is being used only for concept screening or a feasibility study, the estimates are using only models, factoring, judgment, the expected accuracy is only a low range of -15% to -50% and a high range of 20% to 100%, and the effort taken to produce the estimate is at a level of 1 to 4 on a scale of 1 to 100. The range of cost variation makes me hesitant to accept the estimates for ratemaking purposes; however, as the MYRP is based on a forward-looking three-year forecast, costs estimates for projects are more likely to have a wide range of variance, particularly projects that are projected to go into service in the last year of the MYRP.

Project contingencies are commonly used in cost estimation; however, given that project contingency mitigates the risk of unforeseen costs, delays, or other issues for the Company, it is only fair that ratepayers and the Company share the project contingency cost risk for purposes of establishing rates in the MYRP. While I have not researched the issue,

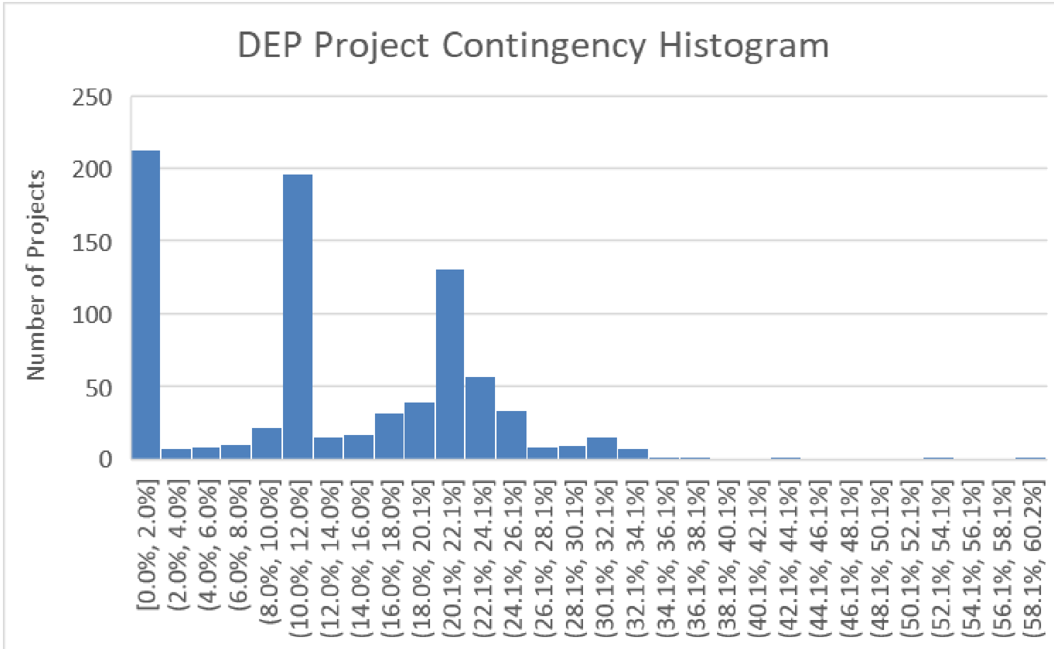
[54] https://www.costengineering.eu/Downloads/articles/AACE_CLASSIFICATION_SYSTEM.pdf

recollect numerous Company projects in the past that came in under or on budget, inclusive of contingency. In these cases, ratepayers paid project costs that included a contingency, regardless of whether the Company used the contingency amount.

As part of the Company's supporting workpapers in the MYRP application, the Company provided a detailed list, by project, of total project contingency and when project contingency costs were identified. Each project type has a different percentage of contingency costs applied to it. The below histogram shows the number of projects that fall within each range-group of contingency percentage of total project budget requested.[55]

[55] The histogram utilized the Company's MYRP February 2023 update.

Figure 28 DEP Project Contingency Histogram



The histogram shows that there are approximately 213 projects with a 0% to ~2% contingency amount and approximately 196 projects with a ~10%-12% contingency range. For the remainder of the projects, the highest contingency is 60% and 64 projects have greater than 25% contingency, but the total contingency for those 64 projects is less than $30M out of the ~$450M total contingency amount for all projects. I am concerned about the risk to ratepayers of projects with greater than ~15%-20% contingency. While it is possible that risks were identified and there is justification for such high contingency in project budgeting, it is not reasonable for ratepayers to absorb such high-risk contingencies. Instead, the Company should further verify the scope of the project and reduce contingency costs.

My proposed adjustment reduces project contingency by half on all projects that were not identified for removal by the Public Staff by the appropriate rate year. It is reasonable to have project contingencies for project cost estimation purposes; however, the contingencies will be included in rates for prospective years. This proposed adjustment balances risk between ratepayers and shareholders and incentivizes the Company to complete projects at or under budget. I have provided this adjustment to the Public Staff Accounting Panel for incorporation in their schedules.

In future MYRPs, the Company should continue to follow project management principles for cost estimation and list project contingencies separately. Further, not all projects require project contingencies. If projects are low risk or routinely completed, they should not qualify for contingencies. Further, the Company may seek recovery of “reasonably and prudently incurred” cost exceedances over and above the contingency in a future rate case, further reducing the Company’s risk.

F. Business Efficiency Adjustment.

Q. Please discuss your intra-business efficiency adjustment.

A. Part of my review of the MYRP looked at how the Company (1) developed the MYRP projects, (2) established funding for each group, and (3) planned the projects, including the executability of the MYRP at a Company-wide level. As I discussed before, one element of the review considered the potential that stale estimates, or changes in project scope, could increase or decrease the project costs or impact project timing.

Two challenging aspects of my review of the MYRP were a review of the transmission business group and the respective timing of transmission project completion. The challenges are due in part to the scope of these projects, the breadth of areas they cover, the timing of each project, and the overlap between transmission and distribution projects in certain areas. I attempted to review the potential that ratepayers would pay for, but not receive, the full benefit of the proposed projects.

The distribution and transmission portions of the MYRP are comprised of hundreds of individual projects. I reviewed the Company's expected staffing, optimization, project loading, and project interdependencies, and concluded that the Company has not yet taken these factors into account in its project planning. I learned through a meeting with the Company[56] that each project estimate stands alone, and the Company has not taken into account any potential synergies in the project estimates.

Stated more clearly, if one assumes that the project estimates are totally correct, the fact remains that the estimates are based on an assumption that project will be implemented in isolation without any synergistic impacts

[56] A meeting between the Public Staff, GDS, and Duke Energy Progress on transmission projects occurred on, March 8, 2023, with Duke Staff Dan Maley and Gary Sullivan participating.

of other ongoing projects. However, some projects can be worked simultaneously, leveraging economies of scale or benefiting from other projects, producing lower total project costs for ratepayers. For purposes of establishing cost estimates, the Company's process is reasonable; however, these estimates are not reflective of final costs and actual project execution until the synergies are considered. The Company indicates that it will take advantage of any construction efficiencies that present themselves during the implementation of the plan to minimize the total costs of the projects. But the Company has not included any efficiency adjustment in its estimates to account for actual performance, thereby resulting in a likely over recovery of project costs.

Public Staff discovery also explored concepts of project dependencies for the transmission and distribution MYRP projects; identifying which projects require completion of one project or sub-project before the next one can begin, and how efficiencies or inefficiencies are taken into account in the Company's MYRP project costs.[57] [58]

For purposes of establishing rates, I propose a 5% downward adjustment to every project's total cost for all transmission and select distribution projects.[59] When the Company seeks full cost recovery in the next general rate case, it may recover all reasonably incurred incremental costs of every project. This adjustment is for the purpose of setting prospective rates for future rate years in this proceeding and does not take into consideration the timing of the projects, staffing risks, or even if the projects are appropriate for inclusion in their respective rate year. I have provided this adjustment to the Public Staff Accounting Panel for incorporation in their schedules.

In future rate cases, I propose that the Public Staff and the Company discuss an "economy of scale" methodology and an efficiency adjustment

---

[57] PS DR 155-15;

Question: For each MYRP project, please indicate whether it has dependencies on other MYRP project in prior rate years (e.g., if there is a Rate Year 2 Substation and a Line project that is dependent upon a Rate Year 1 Substation and Line project's completion, identify and describe each dependency)

Response: At this time, DEP has not identified any MYRP projects that have dependencies between rate years. The primary driver for these dependencies occurs in geographical areas which are sensitive to multiple line clearances at the same time. As work plans are created and continue to mature, clearance requirements will be evaluated at the portfolio level. Work plans will be adjusted accordingly to minimize the number of dependencies between projects.

[58] A similar question was asked in PS DR 155-32 compared to PS DR 155-15 but for distribution. The Company did identify potential program level dependencies but not by project.

[59] Based on discussion with Public Staff witness Thomas, select distribution projects included project efficiencies in the project cost estimates, while others did not.

for purposes of MYRP aggregated rate impacts, and leverage MYRP benefits on the behalf of the ratepayer.

Q. Please list your adjustments to the Company's proposed MYRP.

A. I made three primary adjustments to the Company's proposed MYRP:

- Project Walter addition moved to MYRP Rate Year 1
- Reduction in overall contingency for each MYRP project by Rate Year
- Reduction in total project costs to include a project efficiency adjustment, notably for transmission projects and discrete distribution projects.

Based on the review of GDS and myself, I also removed the following projects from the Company's proposed MYRP:

- Raeford 230kV Substation-Add Redundant Bus Protection
- New Bern 230kV Substation-Add Redundant Bus Protection
- Havelock 230kV Substation-Station Uprate
- Fayetteville 230kV Substation-Add Capacitor
- Craggy-Enka 230kV Construct New line (multiple projects)
- Arden 115kV-Construct New Tap Line
- Sutton-Wallace 230kV Remote Operated Switch
- Carthage 230/115kV-Construct New Substation
- Sutton-Castle Hayne 230kV Line-Remote Operated Switch

Q. Is the Project Walter adjustment the same adjustment as discussed earlier?

A. Yes, I recommend removal of this project from the Base Case test year and inclusion in the MYRP Rate Year 1. This adjustment affects both the Base Case and the MYRP.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009 respectively. I graduated from Central Virginia Community College, receiving Associate of Applied Science degrees in Electronics and Electrical Technology (*Magna Cum Laude*) in 2011 and 2012 respectively, and an Associate of Arts in Science in General Studies (*Cum Laude*) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management. I completed engineering graduate course work in 2019 and 2020 at North Carolina State University.

I have over twelve years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience. My general construction experience includes six years of employment with Framatome, where I provided onsite technical support, craft oversight, and engineer design change packages, as well as participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke and Dominion. I also worked for six years for an industrial and commercial construction company, where I provided field fabrication and installation of electrical components that ranged from low voltage controls to medium voltage equipment, project planning and coordination with multiple work groups, craft oversight, and safety inspections.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on both electric and natural gas matters including general rate cases, fuel cases, annual gas cost reviews, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations), avoided costs and PURPA, interconnection procedures, integrated resource planning, and power plant performance evaluations. I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

Metz Exhibit 1 Index

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 90

Docket No. E-2, Sub 1300

Date of Request: December 20, 2022
Date of Response: December 30, 2022

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 90-1, was provided to me by the following individual(s): Patrick Michael O'Toole, CW- Professional, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 90
DEP Docket No. E2, Sub 1300
Item No. 90-1
Page 1 of 1

Request:

1. In the photograph below, please identify the location of the three existing Duke facilities and the new facility (new building addition(s) for $14.262M project cost):

Response:

1. There were two existing buildings, Maintenance Building & Construction Building, located on the site prior to construction of the new buildings. The "Relay" group and support staff worked out of other Duke Energy buildings, in borrowed space, prior to construction of the new buildings. These other buildings included Hartsville Crew Building, Florence Meter Shop, and the Florence Southern Region Office. After construction was complete on the new main building, the two existing buildings were demolished and all three groups, "Maintenance", "Construction" & "Relay", and support functions/staff moved into the new main building. The buildings that the "Relay" group and support staff were working in before were not demolished. The new buildings include the main building which contains the office space and warehouse/truck bay space and some ancillary buildings that support the operations. The new ancillary buildings include Welding and Crew Equipment Storage & Repairs Building, Hazardous Materials Storage Building, Oil Containment Building, Mobile Transformer Storage Building, and Trucks with Trailer Parking Canopy. See attachment "DEP PS DR 90-1" for aerials photos and associated building labels.
a. Main building (Florence Transmission Headquarters): approximately 22,777 SF for office, warehouse, & truck bays
b. Welding and Crew Equipment Storage & Repairs Building: approximately 2,400 SF used as weld shop and for equipment storage & repairs. Two-sided covered pull-through building with lighting and power.
c. Hazardous Materials Storage Building: approximately 400 SF. Four-sided building.
d. Oil Containment Building: approximately 600 SF. Four-sided building.
e. Mobile Transformer Storage Building: approximately 4,800 SF used for storage of large mobile transformer units. No sides just a canopy with power.
f. Trucks with Trailer Parking Canopy: approximately 2,400 SF. No sides just a canopy with power.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 90

Docket No. E-2, Sub 1300

Date of Request: December 20, 2022
Date of Response: December 30, 2022

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 90-3, was provided to me by the following individual(s): Patrick Michael O'Toole, CW- Professional, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 90
DEP Docket No. E2, Sub 1300
Item No. 90-3
Page 1 of 3

Request:

3. For each of the three older buildings slated for demo and their associated land, please answer the following:
    a. Date of original construction/placed in service.
    b. Expected service life of each building when originally placed into service.
    c. Remaining net book value as of filing of the current general rate case by FERC plant account.
    d. General Ledger journal entries made or expected to be made to remove any remaining balances related to the older buildings, including but not limited to plant, accumulated depreciation, and any gain on sale.
    e. Sum of all capital additions added at each location since it was placed in service.
        i. Detailed list of capital additions added for the following years:
            1. 2014
            2. 2015
            3. 2016
            4. 2017
            5. 2018
            6. 2019

[Note: The intent of this request is to identify the amount of capital additions, if any, that were taking place prior to the new facility being built and whether any capital additions were deferred but for the new building.]

    f. Description of the work functions.
    g. Total office square feet.
    h. Total laydown or work yard square feet (approx. estimate).
    i. Truck bay space.
    j. How many trucks and trailers are typically parked/staged for general work.
    k. Number of employees and equipment:
        i. Expected Staffing and actual Staffing as of 12/31/2017
        ii. Expected Staffing and actual Staffing as of 12/31/2019
        iii. Expected Staffing and actual Staffing as of 12/31/2021
    l. Organization chart and description of positions.
    m. O&M costs for the following years:
            1. 2014
            2. 2015
            3. 2016
            4. 2017
            5. 2018
            6. 2019
            7. 2020
            8. 2021
            9. 2022
    n. Description of whether or not the current building is used and useful.
    o. Are any employees still working in the building(s)?
        i. If so, how many and why?

North Carolina Public Staff
Data Request No. 90
DEP Docket No. E2, Sub 1300
Item No. 90-3
Page 2 of 3

p. Was the land returned/transferred back to "land held for future use"?
    i. If not, please describe why not.
q. Provide a list of test year costs, if any, associated with the existing three buildings, and explain whether the Company made any adjustments in this case to remove those costs and list the adjustment.
r. If any of the three existing buildings are still "used and useful," please describe the function and service provided and why the function and service cannot take place in the new facility.

Response:

3. The two existing buildings, Maintenance Building & Construction Building, were located on existing Duke Energy owned land (2 separate parcels). The new buildings were constructed on the same Duke Energy owned land.
a. Construction Building was originally constructed in 1996, Maintenance Building was originally constructed in 1978.
b. Unknown
c. Both buildings were demolished in mid-September 2020.
d. Both buildings were demolished in mid-September 2020.
e. Capital additions (combined):
i. 2014: Approximately $100,200 (Construction building roof replacement = approx. $56,100, Maintenance building roof replacement = approx. $40,100, Maintenance building security equipment replacement = approx. $4,000)
ii. 2015: N/A
iii. 2016: N/A
iv. 2017: N/A
v. 2018: N/A
vi. 2019: N/A
f. The facilities are the base for the Florence area's transmission line maintenance, substation maintenance, and float track crews. In addition, the facility supports transmission engineering and management.
g. Construction Building was approximately 3,341 SF total (assume 50% office = approximately 1,670 SF) , Maintenance Building was approximately 5,591 SF total (assume 80% office = approximately 4,473 SF)
h. Construction Building laydown/work yard was approximately 39,000 SF, Maintenance Building laydown/work yard was approximately 29,500 SF
i. Construction Building was approximately 3,341 SF total (assume 50% truck bay/warehouse space = approximately 1,670 SF) , Maintenance Building was approximately 5,591 SF total (assume 20% truck bay/warehouse space = approximately 1,118 SF)
j. During normal operations the site has 7 trucks and 8 to 10 trailers. The site also stores a number of large pieces of equipment used by the team.
k.
i. Expected Staffing and actual Staffing as of 12/31/2017 - 43
ii. Expected Staffing and actual Staffing as of 12/31/2019 - 56
iii. Expected Staffing and actual Staffing as of 12/31/2021 - 38, contractor growth TBD

North Carolina Public Staff
Data Request No. 90
DEP Docket No. E2, Sub 1300
Item No. 90-3

l. See attachment "DEP PS DR 90-3" for employee names and positions.
m. O&M costs:
i. 2014: Data not available
ii. 2015: Data not available
iii. 2016: Construction = $16,838, Maintenance = $19,970
iv. 2017: Construction = $20,260, Maintenance = $16,088
v. 2018: Construction = $18,156, Maintenance = $16,109
vi. 2019: Construction = $17,585, Maintenance = $17,873
vii. 2020: Construction = $10,585, Maintenance = $20,448
viii. 2021: N/A
ix. 2022: N/A
n. The two existing buildings, Maintenance Building & Construction Building, were demolished in mid-September 2020.
o. No, the two existing buildings, Maintenance Building & Construction Building, were demolished in mid-September 2020.
p. No. The two existing buildings, Maintenance Building & Construction Building, were located on existing Duke Energy owned land (2 separate parcels). The new buildings were constructed on the same Duke Energy owned land.
q. The two existing buildings, Maintenance Building & Construction Building, were demolished in mid-September 2020.
r. The two existing buildings, Maintenance Building & Construction Building, were demolished in mid-September 2020.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 90

Docket No. E-2, Sub 1300

Date of Request: December 20, 2022
Date of Response: December 30, 2022

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 90-4, was provided to me by the following individual(s): Patrick Michael O'Toole, CW- Professional, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 90
DEP Docket No. E2, Sub 1300
Item No. 90-4
Page 1 of 1

Request:

4. Prior to the completion of the new building, please provide a general narrative of common work and coordination with utilization of the three existing facilities. [Note: The Public Staff would like to understand a common workday and how intraday coordination and discussions would take place.]

Response:

4. Crew members were able to perform work to maintain the grid, but the space needs were constrained for material and equipment. Keeping order of things had its difficulties. See response to PSDR 90-6 for further details.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 90

Docket No. E-2, Sub 1300

Date of Request: December 20, 2022
Date of Response: December 30, 2022

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 90-6, was provided to me by the following individual(s): Patrick Michael O'Toole, CW- Professional, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 90
DEP Docket No. E2, Sub 1300
Item No. 90-6
Page 1 of 1

Request:

6. The Company stated in the response, "The goal of this project is to consolidate the Construction, Maintenance and Relay crews along with support functions for Transmission into a single facility. The staff is currently located in 3 separate facilities. The optimization and re-design of the existing laydown yard is to increase efficiency and provide better fleet vehicle and trailer parking." Please answer the following questions:
   a. Demonstrate how the existing three-building layout was not effective or efficient, and quantify the impacts and lost production on an annual basis.
   b. Describe how the existing laydown yard was inefficient and how fleet and trailer parking was a challenge or ineffective.

Response:

6.
a. Due to the separation of teams and materials, the time needed to deploy from the center to the work was not effective or efficient. A true cost model to quantify this impact was not performed as part of the business case for the new facility.
b. A laydown yard needs proper flow. The original site was not built to suit the size of new vehicles and materials used today. Turning radiuses for vehicles was challenged by the old layout. Due to this, material staging was made more difficult as well.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 90

Docket No. E-2, Sub 1300

Date of Request: December 20, 2022
Date of Response: December 30, 2022

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 90-8, was provided to me by the following individual(s): Patrick Michael O'Toole, CW- Professional, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 90
DEP Docket No. E2, Sub 1300
Item No. 90-8
Page 1 of 1

Request:

8. To the extent possible, please provide pictures/videos of the existing three facilities that illustrate the exterior and interior work spaces. The intent of the question is to gain a visual aid in the condition of the buildings and the associated equipment within/around just prior to demolition or transfer of employees/equipment to the new building.

Response:

8. As explained in response to PS DR 90-1, there were only two existing buildings, Maintenance Building and Construction Building.
See attachment "DEP PS DR 90-8" for photos of the Construction Building and Maintenance Building.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 90

Docket No. E-2, Sub 1300

Date of Request: December 20, 2022
Date of Response: December 30, 2022

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 90-12, was provided to me by the following individual(s): Patrick Michael O'Toole, CW- Professional, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 90
DEP Docket No. E2, Sub 1300
Item No. 90-12
Page 1 of 1

Request:

12. For the new facility, provide the annual O&M cost.
    a. If the new annual O&M cost is greater than the sum of the three existing facilities, please explain why.
    b. If the new annual O&M cost is less than the sum of the three existing facilities, please explain why and list the areas that enabled cost savings.

Response:

12. New facility O&M costs: 2021 = $34,014, 2022 = $45,960
a. Prior to demolition, the Construction and Maintenance buildings saw combined annual O&M costs ranging from $34,266 to $36,809. The Relay group and support staff operated out of the other Duke Energy buildings mentioned in response 1 but the O&M costs can't be quantified since it was in shared space. Using 2022 for the new facility's O&M cost, it is higher, compared against the existing facilities, since there is more SF in the new building and the previous O&M costs from Relay and support staff can't be quantified.
b. N/A

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-1, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

Request:

1. Please provide a general narrative of the Company's five-year capital plan. The narrative should include, but not be limited to, the following topics: date of proposal; date of approval; why changes occurred from the proposal to the approval stages; how the Company evaluates spend per business unit; how the Company prioritizes capital projects in one business unit versus another; how Duke Energy Corporate interfaces in project review and the approval process; general annual timeline of the overall process; and how the five-year plan informs the annual capital spend in the most current calendar year in which it is in effect.

Response:

DEP objects to this set of requests, including this particular request, on the grounds that the information sought is unduly burdensome to produce and is irrelevant to this proceeding. This set of requests appears to be premised upon the supposition that the five-year capital plan is a detailed project-by-project planning and project management tool, which decidedly is not the case. Rather, the Company's five-year capital plan is a top-down financial planning tool and forecast intended as an overview of the Company's projected capital investments. The Company continuously evaluates and refines the five-year capital plan while balancing a variety of priorities including customer, operational, and regulatory needs/commitments. This prioritization is managed within the confines of capital targets set at an enterprise level to optimize cash flow and balance sheet needs.

The detailed, project-by-project projection of multiyear rate year plan (MYRP) capital included as part of DEP's application in this case is substantially different in scope and purpose than the five-year capital plan. Because of this fundamental difference, the five-year capital plan is not relevant to this proceeding. Detailed information concerning the projects included in the Company's MYRP has been provided in connection with the Company's Application and direct testimony, as well as data requests propounded with respect to those projects. Finally, information concerning the development of the Company's five-year capital plan implicates attorney work product and the attorney client privilege to the extent the development of the Company's plan is dependent upon legal analysis and input, e.g., regarding rate case timing and outcome. DEP also objects to this set of requests, including particularly this request, on that basis.

**Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137**

Docket No. E-2, Sub 1300

**Date of Request: January 20, 2023
Date of Response: February 15, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached supplemental response to NC Public Staff Data Request No. 137-1, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-1
Page 1 of 1

Request:

1. Please provide a general narrative of the Company's five-year capital plan. The narrative should include, but not be limited to, the following topics: date of proposal; date of approval; why changes occurred from the proposal to the approval stages; how the Company evaluates spend per business unit; how the Company prioritizes capital projects in one business unit versus another; how Duke Energy Corporate interfaces in project review and the approval process; general annual timeline of the overall process; and how the five-year plan informs the annual capital spend in the most current calendar year in which it is in effect.

Supplemental Response (Feb. 15, 2023):

The Company's formal capital planning process occurs within an annual cycle. An annual capital budget is set for the enterprise and each jurisdiction based on information received from the various functions (i.e., transmission, distribution, nuclear, etc.). During the Spring, capital targets are set for each jurisdiction and function that recognize regulatory commitments and requirements, as well as operational needs, while also optimizing cash flow and balance sheet needs. For example, capital projects approved as part of a MYRP would be deemed regulatory requirements and be factored into the capital target for a particular jurisdiction/function. These targets are developed based on input received from each function within each jurisdiction.

Over the Summer, capital projects across all jurisdictions and functions undergo an extensive evaluation and prioritization process by operational leadership to ensure that the highest priority projects (from a variety of perspectives, including customer, operational, and regulatory) are funded. In the late summer timeframe, the functional five-year capital plans are approved by the appropriate State President and are then incorporated into the overall enterprise financial plan which is approved by senior leadership (including the CEO and CFO) and the Board of Directors by the end of the year. On a year-to-year basis, this process is cyclically inter-related; that is, the targets sent to the jurisdictions/functions in the Spring are informed by the plan approval that occurs at year-end, and then the year-end approvals are informed by the jurisdiction/function planning processes that occur from the Spring and through the Summer.

The enterprise-level five-year capital plan does not include the level of detail that is included in the operational plans maintained by individual functions, which include MYRP projects and the qualitative justification of why a function is spending on a given project. For example, the five-year operational plan developed by the Carolina's distribution delivery team provides the project level detail that they will execute on, such as project costs, spend by month, in-service dates, etc. In addition, each function manages capital within their individual function utilizing planning tools to prioritize projects based on different factors (i.e., customer needs, regulatory requirements, operational considerations, etc.). Note, however, monthly jurisdictional and cross-functional forums are in place to reprioritize capital as needed, based on the recommendations of functional leaders. Senior leadership must approve any material deviations from approved capital targets.

Finally, at the enterprise level, forecasting validates that certain strategic projects/initiatives are funded appropriately (i.e., discrete Carbon Plan capital) and reflects the same total spend and in-service assumptions as those contained in the individual functions' five-year plans. As this evidences, the enterprise level five-year capital plan is a snapshot in time as project priorities and costs continuously change based on real-time events.

DUKE ENERGY

March 2019 Update

DUKE ENERGY®

BUILDING A SMARTER ENERGY FUTURE®

DUKE ENERGY.

Safe Harbor statement

This presentation includes forward-looking statements within the meaning of the federal securities laws. Actual results could differ materially from such forward-looking statements. The factors that could cause actual results to differ are discussed in the Appendix herein and in Duke Energy's SEC filings, available at www.sec.gov.

Regulation G disclosure

In addition, today's discussion includes certain non-GAAP financial measures as defined under SEC Regulation G. A reconciliation of those measures to the most directly comparable GAAP measures is available in the Appendix herein and on our Investor Relations website at www.duke-energy.com/investors/.

Our investor value proposition

DUK
LISTED
NYSE

A SOLID LONG-TERM HOLDING

4.1%

DIVIDEND YIELD(1) WITH DIVIDEND GROWTH COMMITMENT(2)

~8-10%

ATTRACTIVE RISK-ADJUSTED TOTAL SHAREHOLDER RETURN(3)

4-6%

HIGHLY ACHIEVABLE EPS GROWTH THROUGH 2023(4)

CONSTRUCTIVE JURISDICTIONS, LOW-RISK REGULATED INVESTMENTS AND BALANCE SHEET STRENGTH

(1) As of Feb. 28, 2019
(2) Subject to approval by the Board of Directors.
(3) Total shareholder return proposition at a constant P/E ratio
(4) Based on adjusted diluted EPS off the midpoint of the 2019 guidance range ($5.00) as presented in the Fourth Quarter 2018 Earnings Review and Business Update on Feb. 14, 2019

Advancing our strategic vision

TRANSFORM THE CUSTOMER EXPERIENCE

MODERNIZE THE ENERGY GRID

GENERATE CLEANER ENERGY

EXPAND NATURAL GAS INFRASTRUCTURE

STAKEHOLDER ENGAGEMENT

EMPLOYEE ENGAGEMENT AND OPERATIONAL EXCELLENCE ARE FOUNDATIONAL TO OUR SUCCESS

Duke Energy – a large scale, highly regulated energy infrastructure company

HEADQUARTERED IN CHARLOTTE, NC

DUK
LISTED
NYSE

A FORTUNE 125 COMPANY

$65 B
MARKET CAP
(AS OF 2/28/2019)

$145 B
TOTAL ASSETS
(AS OF 12/31/2018)

30 K
EMPLOYEES
(AS OF 12/31/2018)

54 GWs
TOTAL GENERATING CAPACITY (AS OF 12/31/2018)

DUKE ENERGY.

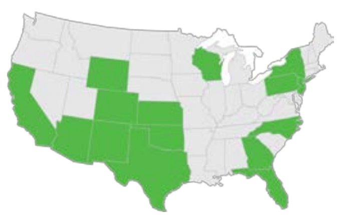
ELECTRIC UTILITIES & INFRASTRUCTURE

- Operating in six constructive jurisdictions, with attractive allowed ROEs, serving 7.7 million retail customers
- Below average customer rates[(1)]
- Balanced generation portfolio
- Industry-leading safety performance, as recognized by EEI

GAS UTILITIES & INFRASTRUCTURE

- Five state LDCs serving 1.6 million customers
- Strong earnings trajectory driven by customer growth, system integrity improvements, and continued expansion of natural gas infrastructure
- Significant investments in midstream natural gas pipelines and storage facilities

COMMERCIAL RENEWABLES

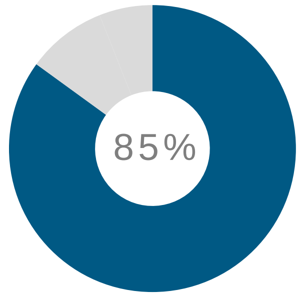


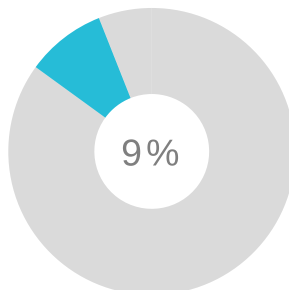
- Invested ~$5 billion over the past 10 years
- Approximately 3 GWs of wind and solar on-line
- Long-term Power Purchase Agreements with creditworthy counterparties

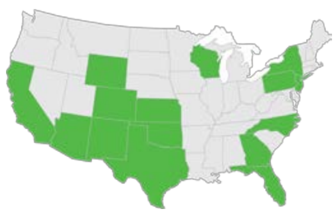
(1) Source: EEI Typical Bills and Average Rates Report, Summer 2018

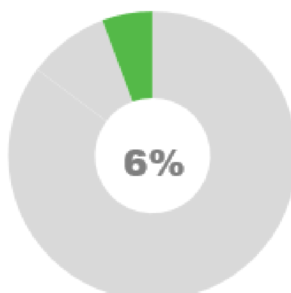
Complementary businesses with strong growth opportunities

	2019 ADJUSTED EPS CONTRIBUTION(1)	2019-2023 GROWTH CAPITAL
ELECTRIC UTILITIES & INFRASTRUCTURE	85%	$29.0 B
GAS UTILITIES & INFRASTRUCTURE	9%	$6.0 B
COMMERCIAL RENEWABLES	6%	$2.5 B



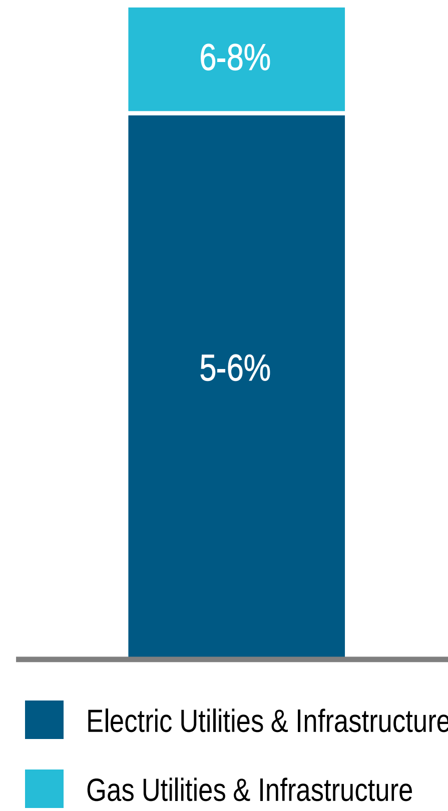






2019 – 2023 ADJUSTED EPS CAGR(2)

Consolidated
4-6%



(1) Based upon the midpoint of the 2019 adjusted diluted EPS guidance range of $4.80-$5.20 per share as presented in the Fourth Quarter 2018 Earnings Review and Business Update on Feb. 14, 2019; excludes the impact of Other

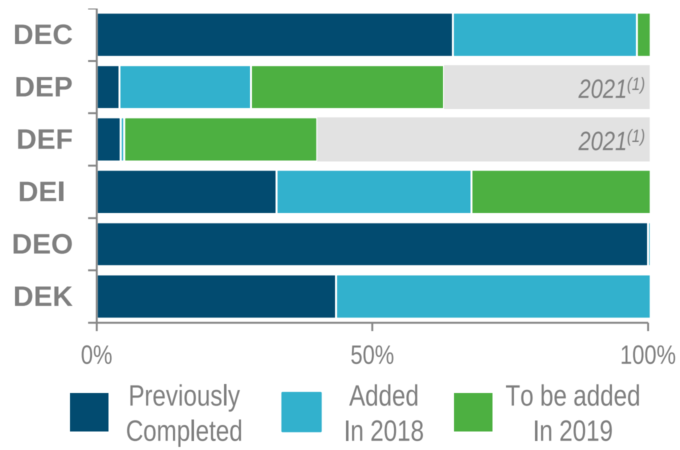
(2) Based upon the midpoint of the 2019 adjusted diluted EPS guidance range of $4.80-$5.20 per share as presented in the Fourth Quarter 2018 Earnings Review and Business Update on Feb. 14, 2019; consolidated growth rate includes the impact of Commercial Renewables and Other

Modernizing the energy grid

GRID IMPROVEMENT PLAN HIGHLIGHTS

- Investing in battery storage and electric vehicle infrastructure
  - Announced $500 million in battery storage in the Carolinas over next 15 years
  - Launched EV pilot program in FL and advancing programs in other jurisdictions
- Spending ~ $500 million annually in the Midwest on grid investment
  - DEO distribution capital investments rider extended through 2025
- $1.1 billion grid program in FL recovered via annual base rate step-ups starting in 2019
- Secured deferral treatment in SC; Continuing stakeholder engagement in the Carolinas

AMI DEPLOYMENT



PRIMARY RECOVERY MECHANISMS

Carolinas	Base rate cases
Florida	Multi-year base rate plan
Indiana	TDSIC rider
Ohio	DCI and BTR riders
Kentucky	Base rate cases

DELIVERING CUSTOMER BENEFITS AS WE ADVANCE OUR GRID IMPROVEMENT PLANS

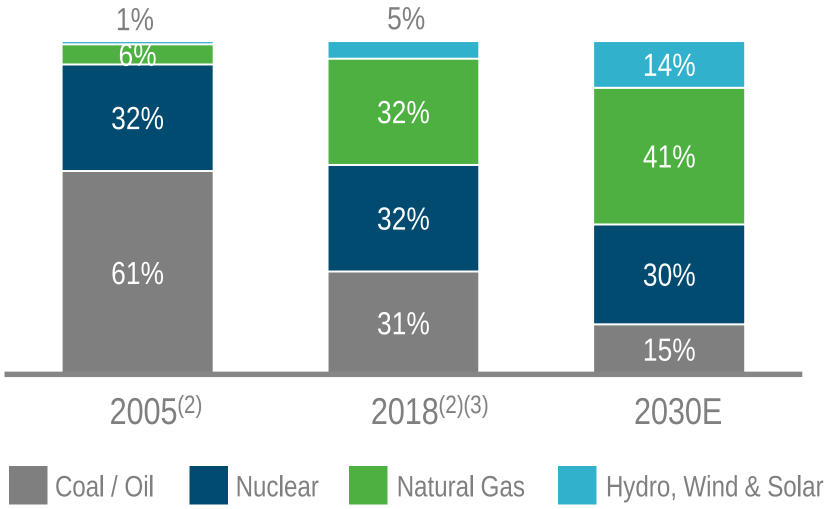
(1) *Year of full deployment*

Generating cleaner energy

RETIRING COAL...

- Retired ~6 GW of coal between 2011 and 2018
- Plan to retire additional ~1 GW of coal by 2024

FUEL DIVERSITY
(MWh OUTPUT)



...REPLACING WITH LOWER-CARBON ALTERNATIVES

HIGHLY-EFFICIENT NATURAL GAS

- W.S. Lee (DEC) and Citrus County (DEF) CCGTs in service in 2018
- Western Carolinas Modernization Project (DEP) on track for late 2019 in-service

ZERO-CARBON NUCLEAR

- Largest regulated nuclear fleet in the U.S.
- Evaluating extended licenses for nuclear fleet

RENEWABLES

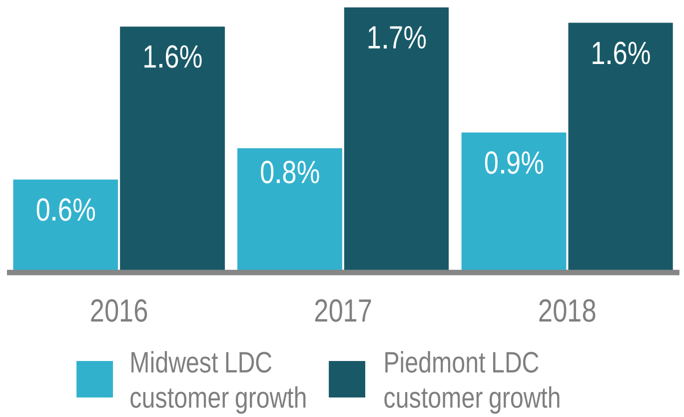
- Building up to 700 MW solar in FL through 2021
- Increasing solar in NC under HB589; with first RFP for 680 MW underway
- Over 1,000 MW of Commercial Renewables projects in late stages of development
  - Pivoted to utilizing tax equity financing

TARGETING 40% REDUCTION IN CO_2 EMISSIONS BY 2030 FROM 2005 LEVELS[1]

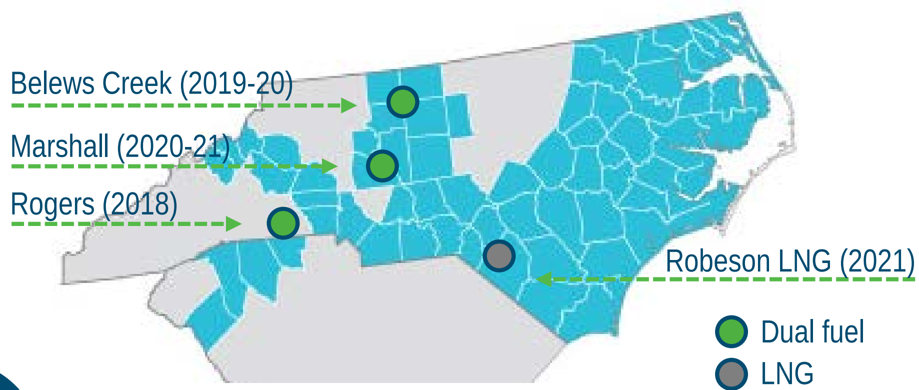
(1) 2030 carbon reduction will be influenced by customer demand, generation mix, weather, fuel availability and prices
(2) 2005 and 2018 data based on Duke's ownership share of U.S. generation assets as of Dec. 31, 2018
(3) 2018 data excludes 8,519 GWh of purchased renewables, equivalent to ~4% of Duke's output

Expanding natural gas infrastructure

GAS UTILITIES RESIDENTIAL GROWTH TRENDS



DUAL-FUEL AND LNG PROJECTS

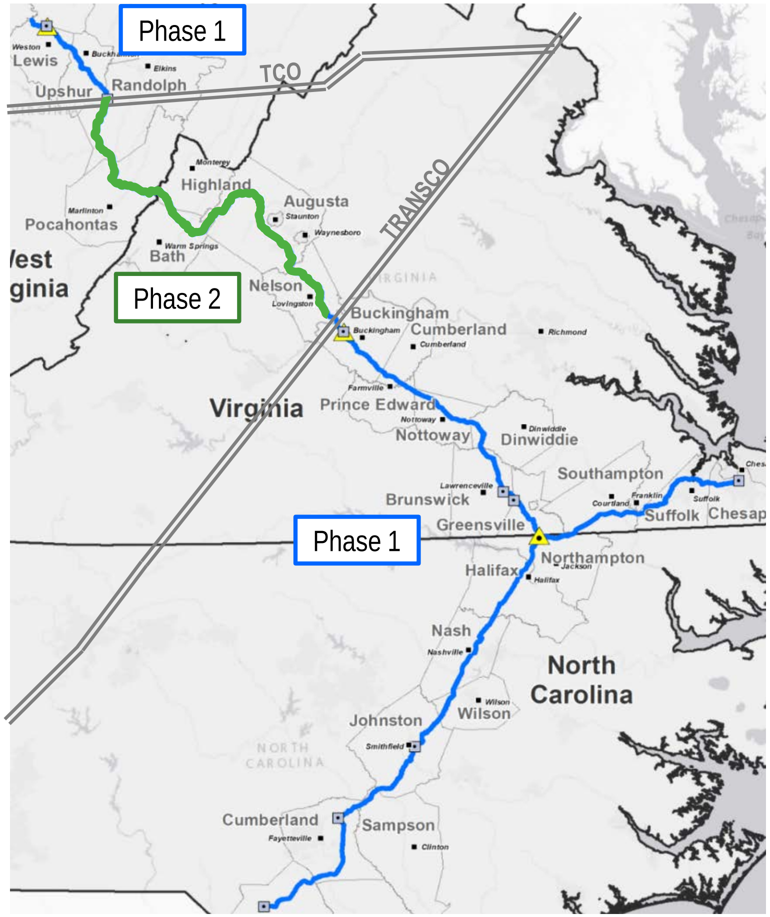


LDC GROWTH AND GAS INFRASTRUCTURE INVESTMENTS

- Strong customer growth drives margin growth supported by decoupling mechanisms
- Ongoing Integrity Management Programs (IMR) recovered via riders
- Dual-fuel projects at coal-fired units provide fuel flexibility and emissions reductions
- $250 million investment in Robeson LNG facility
  - Construction to begin in 2019 with 2021 in service expected

LDCs WITH STRONG ORGANIC GROWTH COMPLEMENT ELECTRIC UTILITIES

Atlantic Coast Pipeline update



PERMIT STATUS

- Received major DEQ permits in NC and VA in 2018, and air permit for Buckingham compressor station in January 2019
- U.S. Fish & Wildlife Service Biological Opinion and Incidental Take Statement stayed
  - Hearing expected in May
- U.S. Forest Service permit to cross national forests remanded; permission to cross Appalachian Trail vacated
  - Evaluating potential administrative and legislative options
  - Expect to also pursue an appeal to the Supreme Court

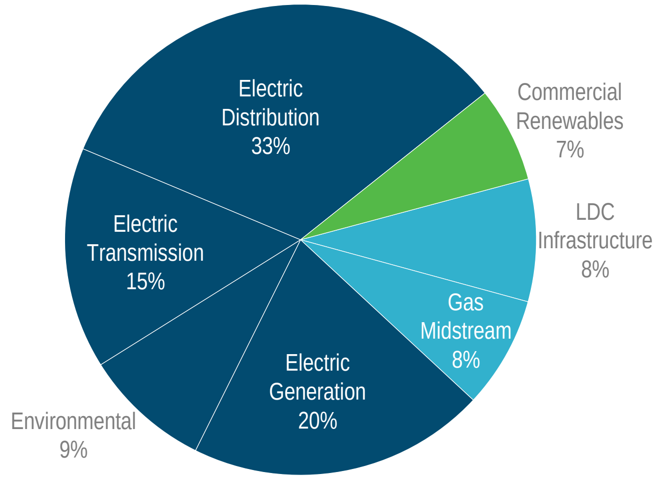
REVISED IN-SERVICE DATES AND COST ESTIMATE

- Expect construction to resume this Fall, with the full project in-service in 2021
  - Pursuing phased in-service schedule, with Phase 1 in service by late 2020 and Phase 2 in 2021
- Estimated cost has increased to $7.0 to $7.8 billion

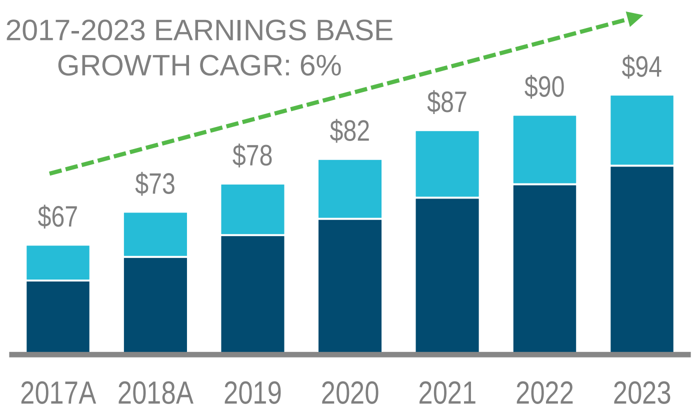
COMMITTED TO BRINGING LOW-COST NATURAL GAS TO UNDERSERVED SOUTHEAST

Long-term growth underpinned by robust capital plan

$37 BILLION GROWTH CAPITAL PLAN 2019 - 2023

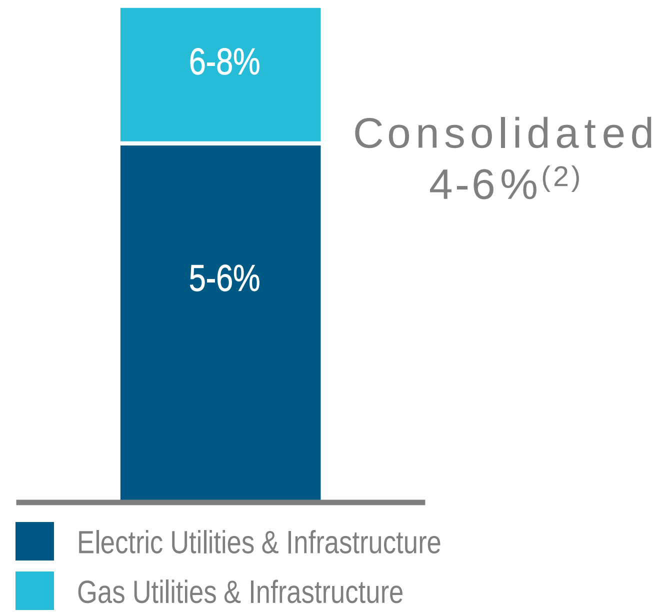


REGULATED ELECTRIC AND GAS EARNINGS BASE(3)



EXTENDING 4-6% LONG-TERM GROWTH CAGR THROUGH 2023 OFF OF 2019 GUIDANCE RANGE MIDPOINT

2019 – 2023 ADJUSTED EPS CAGR(1)



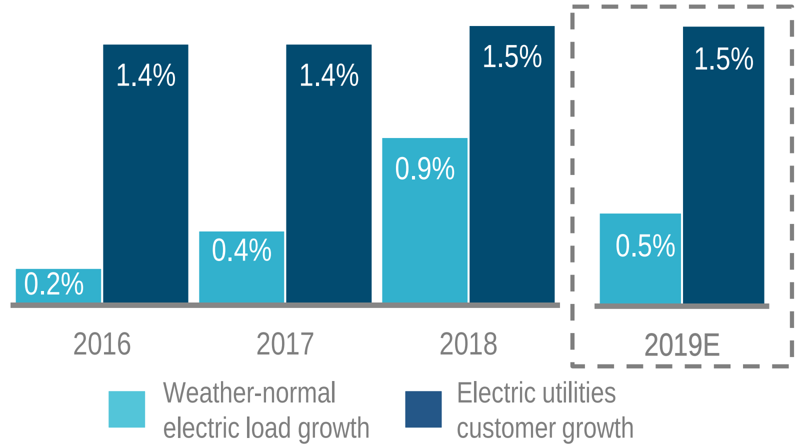
(1) CAGR and relative segment contributions based on midpoint of 2019 guidance, or $5.00 per share, as presented in the Fourth Quarter 2018 Earnings Review and Business Update on Feb. 14, 2019

(2) Includes Commercial Renewables and Other. Other primarily includes interest on HoldCo debt.

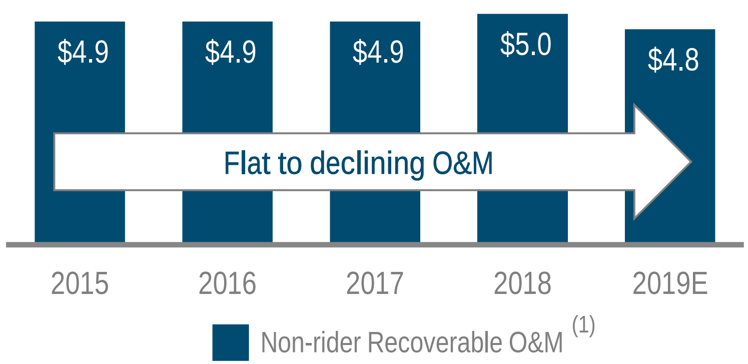
(3) Illustrative earnings base for presentation purposes only and includes retail and wholesale; Amounts as of the end of each year shown; Projected earnings base = prior period earnings base + capex - D&A - deferred taxes

Strong customer growth and O&M management support growth

ELECTRIC RESIDENTIAL GROWTH AND RETAIL VOLUME TRENDS



O&M COST MANAGEMENT
($ IN BILLIONS)



LOAD GROWTH TRENDS

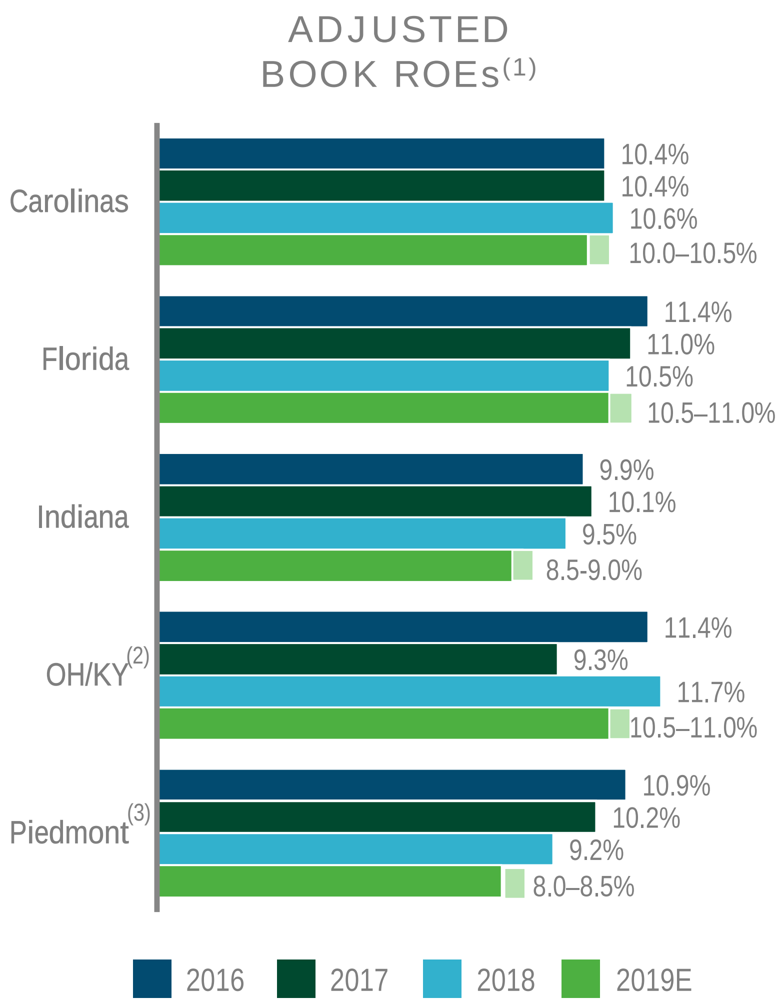
- Higher electric usage per customer in 2018 for the first time in more than five years
- Continued population migration to the Southeast drives customer and volume growth for electric and gas utilities

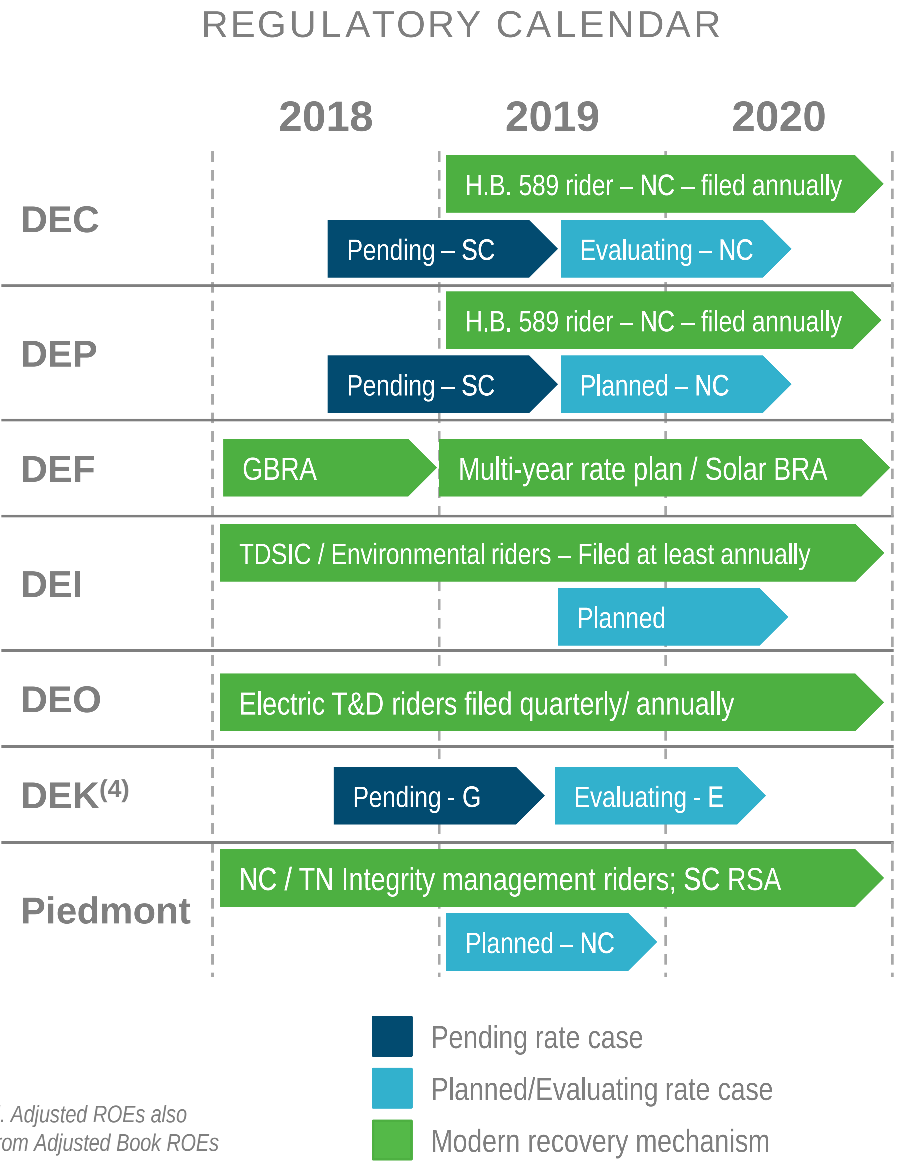
COST STRUCTURE OPTIMIZATION CONTINUES

- Leveraging increased cost flexibility capabilities to keep non-rider recoverable O&M flat despite inflation
- Utilizing cost saving opportunities from increased productivity, mobile technology deployments and demographic shifts in the workforce
- Employing data analytics and digital capabilities to enhance decision making and prioritization

(1) Non-rider Recoverable O&M excludes special items and other non-recoverable charges incurred. For a reconciliation to GAAP O&M see accompanying materials at www.duke-energy.com/investors

Managing regulatory calendar to earn allowed ROEs





(1) Adjusted book ROEs exclude special items and are based on average book equity less Goodwill. Adjusted ROEs also include wholesale and are not adjusted for the impacts of weather. Regulatory ROEs will differ from Adjusted Book ROEs
(2) Combined electric and gas utilities
(3) Piedmont's 2016 ROE is based on the year ended October 31 (Piedmont's legacy fiscal year-end)
(4) "E" denotes Electric; "G" denotes Gas

Maintaining balance sheet strength

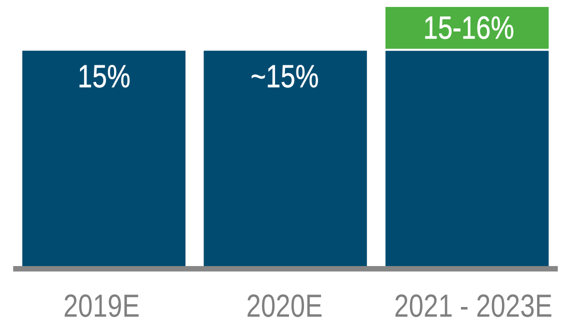
KEY MESSAGES

- Committed to maintaining strong credit quality, including investment-grade ratings
- Expected equity issuances of $500 million per year 2019-2023 via DRIP/ATM programs
- $1.1 billion refundable AMT credits provide FFO in 2019-2022
  - ~$575 million expected to be refunded in 2019 and ~$275 million expected in 2020
- Credit metrics strengthen over the planning horizon

PRIMARY CREDIT METRICS

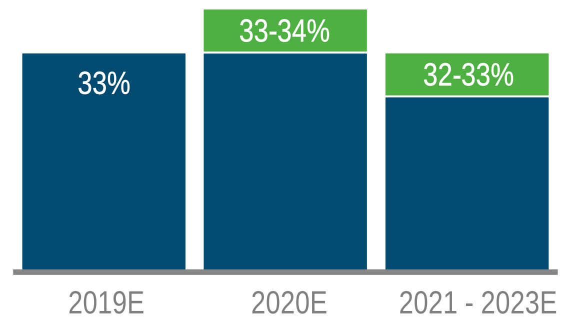
FFO/DEBT

Target: 15 - 16%



HOLDCO DEBT %

Target: Low 30%'s



Ongoing commitment to dividend growth

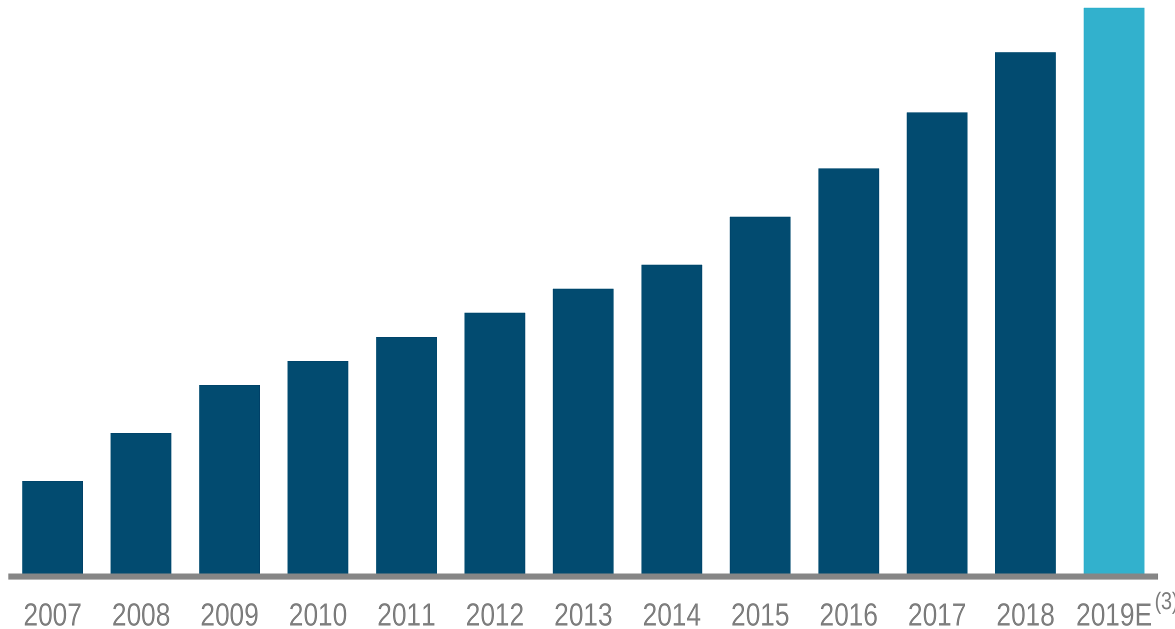
65 - 75%

LONG-TERM TARGET PAYOUT RATIO(1)

~80%

OF TSR ACHIEVED THROUGH DIVIDEND REINVESTMENT OVER LAST 20 YEARS

2019 WILL BE 13TH CONSECUTIVE YEAR OF DIVIDEND GROWTH(2)(3)



(1) Based on adjusted diluted EPS
(2) Reflects annualized Q4 dividend per share for each year
(3) Subject to approval by the Board of Directors

Appendix

2018 review and 2019 guidance support

Delivered on our commitments in 2018

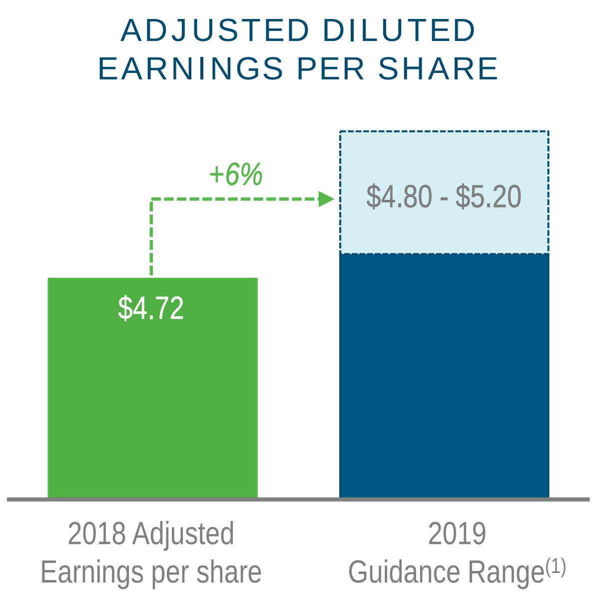
WHAT WE SAID…	…WHAT WE DID
Narrowed 2018 adjusted diluted EPS guidance range of $4.65 to $4.85	✓ Delivered within narrowed guidance range and above original guidance midpoint
Grow 2019 adjusted diluted EPS within long-term CAGR range	✓ Introduced 2019 guidance range, with midpoint ~4% CAGR from 2017 guidance midpoint ($4.60)
Continue growing the dividend	✓ Increased the dividend 4.2% in 2018
Address the effects of tax reform	✓ Issued $2 billion common equity to support the balance sheet ✓ Achieved constructive tax reform-related outcomes across the jurisdictions
Continue active regulatory calendar to recover investments	✓ Successfully completed rate cases (DEP-NC, DEC-NC, DEO and DEK) ✓ Filed rate cases for DEC-SC and DEP-SC
Maintain focus on employee safety and operational excellence	✓ Industry-leading safety results ✓ Exceptional response to 3 million hurricane-related outages in 3Q/4Q 2018 ✓ Achieved nuclear capacity factor above 90% for 20th consecutive year

DUKE ENERGY

2019 financial outlook

KEY MESSAGES

- Achieved 2018 adjusted EPS in top half of original 2018 guidance range
- 2019 guidance range midpoint of $5.00 is consistent with prior growth guidance[(1)]



2019 DRIVERS

Electric Utilities & Infrastructure

- ⬆ Investment programs
  - Western Carolinas Modernization Project
  - FL grid, GBRA & SoBRA
  - Midwest grid riders
- ⬆ Base rate increases in NC and SC
- ⬆ Retail & wholesale load growth
- ⬆ O&M
- ⬇ Regulatory lag

Gas Utilities & Infrastructure

- ⬆ Midstream and integrity management investments
- ⬆ Base rate increases at Piedmont-NC and KY
- ⬆ Customer growth

Commercial Renewables

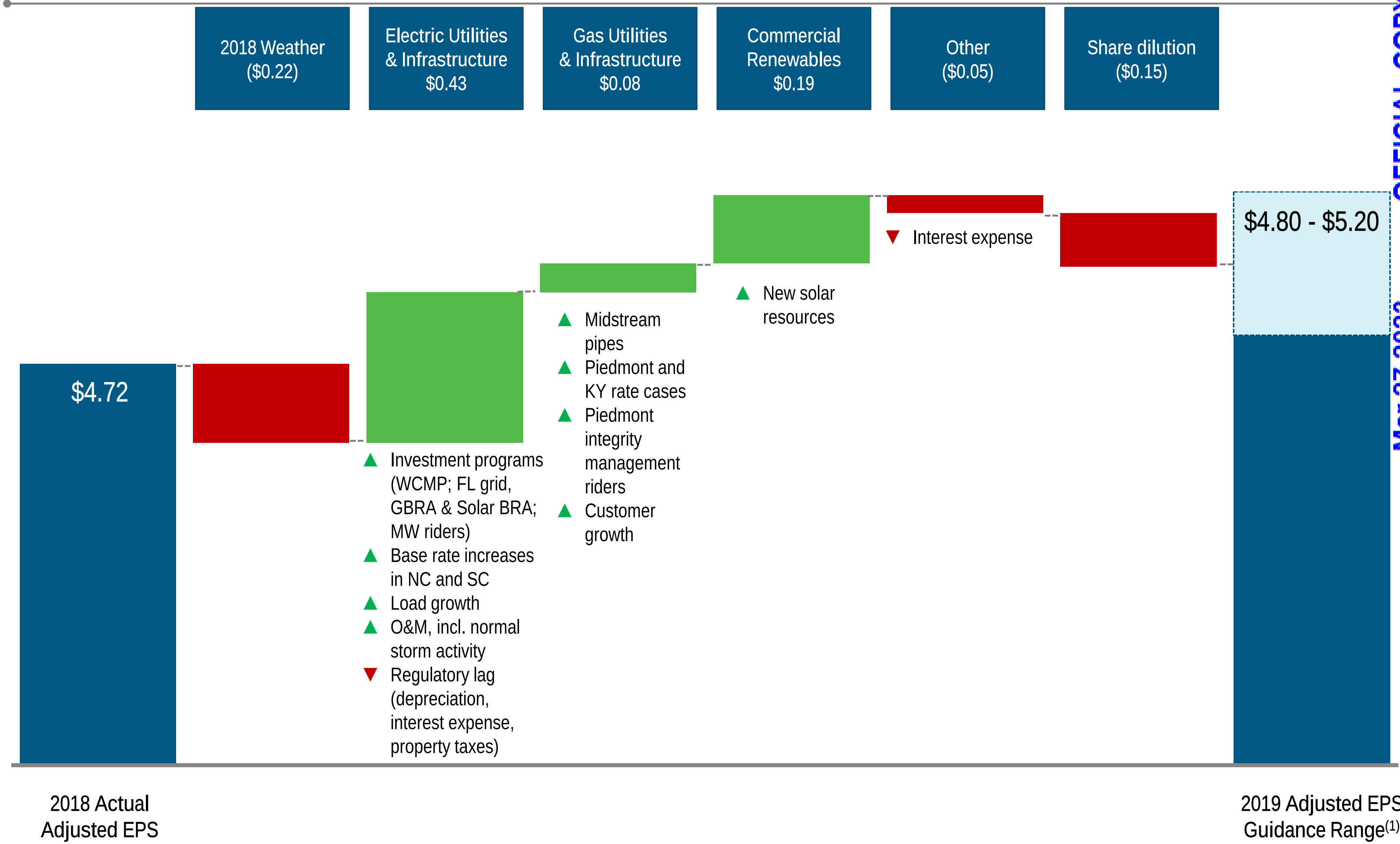
- ⬆ New solar projects in service

Other Drivers

- ⬇ Interest expense
- ⬇ Share dilution

(1) Based on adjusted diluted EPS. As presented on the in the Fourth Quarter 2018 Earnings Review and Business Update on Feb. 14, 2019

2018-2019 adjusted diluted EPS waterfall

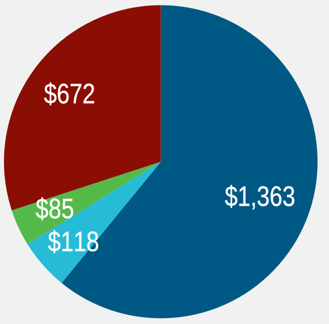


(1) *As presented on the in the Fourth Quarter 2018 Earnings Review and Business Update on Feb. 14, 2019*

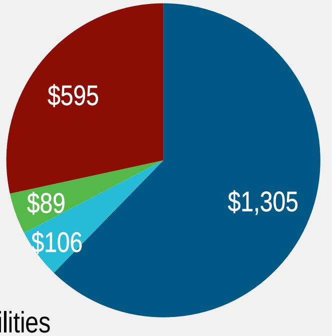
Key 2019 adjusted earnings guidance assumptions

($ in millions)	Orig. 2018 Assumptions	2018 Actual	2019 Assumptions
Adjusted segment income/(expense) (1):			
Electric Utilities & Infrastructure	$3,304	$3,330	$3,480
Gas Utilities & Infrastructure	$319	$317	$375
Commercial Renewables	$117	$97	$230
Other	($383)	($405)	($440)
Duke Energy Consolidated	$3,357	$3,339	$3,645
Additional consolidated information:			
Interest expense	$2,067	$2,094	$2,238
Adjusted effective tax rate	15-16%	15%	12-14%
Debt AFUDC and capitalized interest	$152	$161	$151
AFUDC equity	$220	$221	$168
Capital expenditures (2)(3)	$10,950	$10,612	$11,100
Weighted-average shares outstanding	~714 million	~708 million	~729 million

2019 Interest Expense Assumption
(Consolidated Total $2,238)



2018 Interest Expense
(Consolidated Total $2,094)



Electric Utilities
Gas Utilities
Commercial Renewables
Other

(1) Adjusted net income for 2019 assumptions is based upon the midpoint of the adjusted diluted EPS guidance range of $4.80 to $5.20, as presented on the in the Fourth Quarter 2018 Earnings Review and Business Update on Feb. 14, 2019
(2) Includes debt AFUDC and capitalized interest
(3) 2018 Actual includes coal ash closure spend of ~$500 million that was included in operating cash flows and $460 million funded under the ACP revolving credit facility. 2019 Assumptions include ~$850 million of projected coal ash closure spend and $220 million projected to be funded under the ACP revolving credit facility

Electric utilities quarterly weather impacts

Weather segment income to normal:	2018			2017		
	Pretax impact	Weighted avg. diluted shares	EPS impact[1] favorable / (unfavorable)	Pretax impact	Weighted avg. shares	EPS impact[1] favorable / (unfavorable)
First Quarter	$10	701	$0.01	($175)	700	($0.15)
Second Quarter	$90	704	$0.10	($5)	700	($0.01)
Third Quarter[2]	$55	714	$0.05	$20	700	$0.02
Fourth Quarter	$60	716	$0.06	$20	700	$0.02
Year-to-Date[2][3]	$215	708	$0.22	($140)	700	($0.12)

4Q 2018	Duke Energy Carolinas		Duke Energy Progress		Duke Energy Florida		Duke Energy Indiana		Duke Energy Ohio/KY	
Heating degree days / Variance from normal	1,333	5.9%	1,128	(0.7%)	192	(2.9%)	2,090	6.1%	1,916	4.0%
Cooling degree days / Variance from normal	115	243.9%	143	161.2%	612	31.6%	83	433.6%	93	449.1%

4Q 2017	Duke Energy Carolinas		Duke Energy Progress		Duke Energy Florida		Duke Energy Indiana		Duke Energy Ohio/KY	
Heating degree days / Variance from normal	1,196	(5.7%)	1,102	(3.1%)	131	(33.3%)	1,970	(0.6%)	1,842	(0.6%)
Cooling degree days / Variance from normal	83	144.1%	115	113.0%	550	17.5%	38	153.3%	46	187.5%

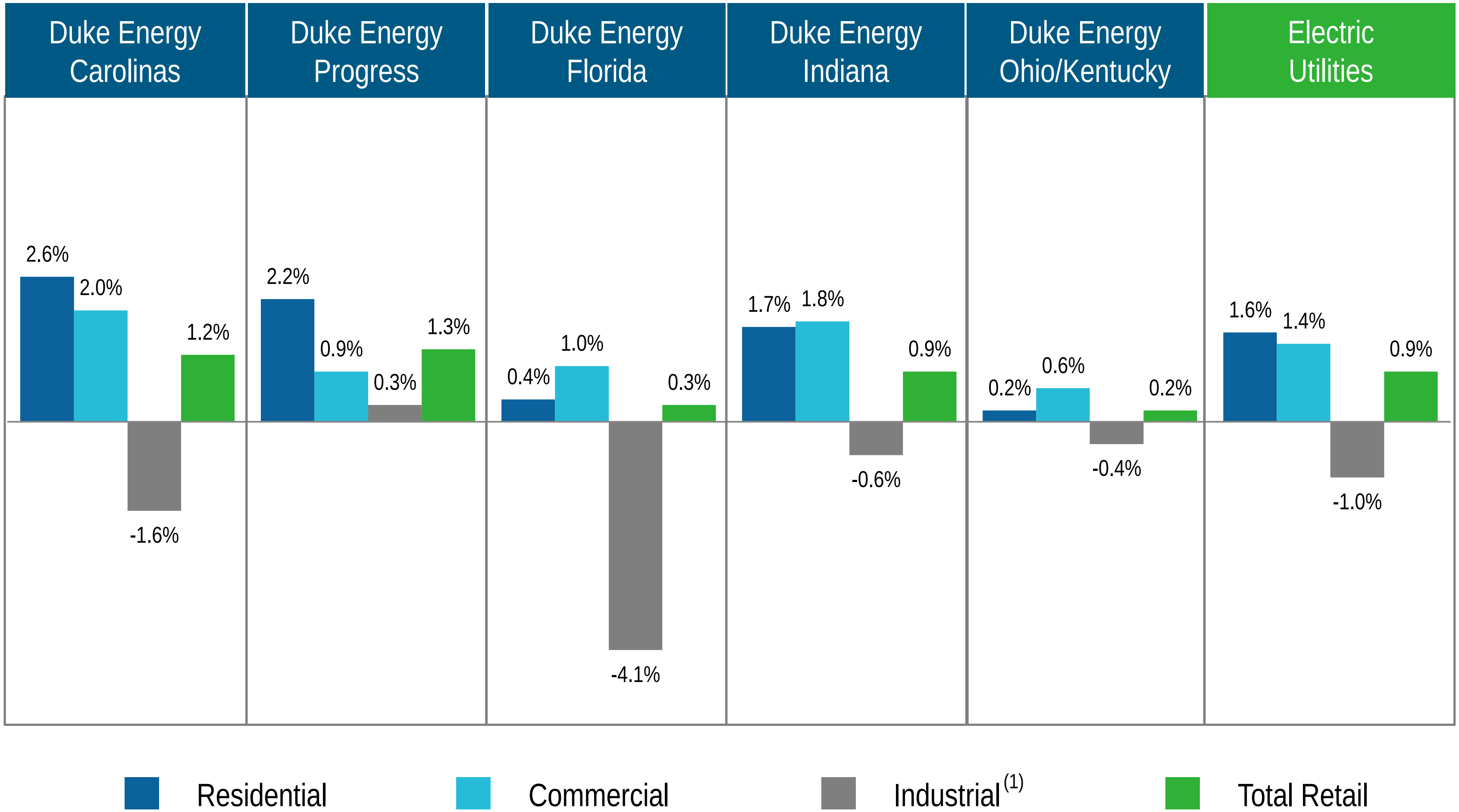
(1) 2018 EPS impacts are based on the 2018 consolidated statutory tax rate. 2017 EPS impacts are based on the 2017 consolidated statutory tax rate.

(2) 2017 includes an unfavorable ~$20 million or $0.02/share impact from Hurricane Irma. 2018 includes an unfavorable ~$15 million or $0.01/share impact from Hurricane Florence.

(3) Year-to-date amounts may not foot due to differences in weighted-average shares outstanding and/or rounding.

Weather normalized volume trends, by electric jurisdiction

Rolling Twelve Months, as of Dec. 31, 2018



(1) Electric Utilities industrial results have been impacted by production interruptions at a couple of large customers

Key 2019 earnings sensitivities

Driver		EPS Impact
Electric Utilities & Infrastructure	1% change in earned return on equity	+/- $0.49
	$1 billion change in rate base	+/- $0.07
	1% change in volumes	+/- $0.13
Gas Utilities & Infrastructure	1% change in earned return on equity	+/- $0.06
	$200 million change in rate base	+/- $0.01
	1% change in number of new customers	+/- $0.01
Consolidated	1% change in interest rates[1]	+/- $0.07

Note: EPS amounts based on forecasted 2019 share count of ~729 million shares

(1) Based on average variable-rate debt outstanding throughout the year.

2019 pension funding and costs

- On a consolidated basis, Duke Energy pension plans are fully funded as of 12/31/2018 on a PBO basis
- Duke Energy's pension funding policy:
  - Duke Energy's policy is to fund amounts on an actuarial basis to provide assets sufficient to meet benefit payments to be paid to plan participants
  - Duke has a targeted allocation of 58% fixed-income assets and 42% return-seeking assets

Pension Contributions *($ in millions)*	2017A	2018A	2019E
All plans	$19	$141	$0

- Key 2019 assumptions (as of Dec. 31, 2018):
  - Discount rate: 4.3% for 2019 (vs. 3.6% for 2018)
  - Expected long-term return of 6.85% on plan assets (increase of 35 bps from 2018 assumption)

Regulated utilities end of year earnings base[1]

Electric Utilities Earnings Base

($ in billions)	2018A	2019E	2020E	2021E	2022E	2023E
Duke Energy Carolinas	$23.9	$24.8	$25.9	$27.1	$27.9	$29.3
Duke Energy Progress	17.0	17.9	17.9	18.5	19.5	20.2
Duke Energy Florida	12.9	14.1	15.2	16.3	17.1	17.8
Duke Indiana	8.0	8.4	8.7	8.8	8.8	9.1
Duke Ohio – Electric	2.5	2.8	3.1	3.2	3.4	3.5
Duke Kentucky – Electric	0.9	1.0	1.1	1.2	1.2	1.3
Electric Utilities Total[2]	$65.2	$69.0	$71.9	$75.1	$77.9	$81.2

Gas Utilities Earnings Base

($ in billions)	2018A	2019E	2020E	2021E	2022E	2023E
Piedmont	$4.5	$5.1	$5.4	$5.9	$6.1	$6.4
Duke Energy Ohio – Gas	1.4	1.5	1.9	1.8	1.8	1.7
Duke Energy Kentucky - Gas	0.3	0.4	0.4	0.4	0.5	0.5
Natural Gas Transmission	1.7	2.1	3.1	3.8	3.9	3.9
Gas Utilities Total[2]	$7.9	$9.1	$10.5	$11.9	$12.2	$12.5

(1) Illustrative earnings base for presentation purposes only and includes retail and wholesale; Amounts as of the end of each year shown; Projected earnings base = prior period earnings base + capex – D&A – deferred taxes
(2) Totals may not foot due to rounding

DUKE ENERGY.

Capital expenditures profile(1)

($ in millions)

Electric Utilities & Infrastructure		2018A		2019E		2020E		2021E		2022E		2023E		2019 - 2023
Electric Generation(2)	$	1,821	$	1,550	$	1,375	$	1,575	$	1,425	$	1,725	$	7,650
Electric Transmission		916		1,050		1,200		1,050		1,325		1,075		5,700
Electric Distribution		1,829		2,375		2,500		2,450		2,500		2,525		12,350
Environmental & Other(3)		1,201		1,150		850		575		375		325		3,275
Electric Utilities & Infrastructure Growth Capital	$	5,767	$	6,125	$	5,925	$	5,650	$	5,625	$	5,650	$	28,975
Maintenance		2,809		2,375		1,800		1,800		1,825		2,425		10,225
Total Electric Utilities & Infrastructure Capital	$	8,576	$	8,500	$	7,725	$	7,450	$	7,450	$	8,075	$	39,200
Commercial Renewables(4)	$	154	$	675	$	550	$	400	$	450	$	375	$	2,450
Total Commercial Renewables Capital	$	154	$	675	$	550	$	400	$	450	$	375	$	2,450
Midstream Pipelines(5)		726		475		1,100		775		275		250		2,875
LDC - Non-Rider		278		650		450		350		275		250		1,975
LDC - Rider		265		275		200		225		200		275		1,175
Gas Utilities & Infrastructure Growth Capital	$	1,268	$	1,400	$	1,750	$	1,350	$	750	$	775	$	6,025
Maintenance		350		275		250		250		175		175		1,125
Total Gas Utilities & Infrastructure Capital	$	1,618	$	1,675	$	2,000	$	1,600	$	925	$	950	$	7,150
Other(6)		263		250		275		225		225		250		1,225
Total Duke Energy	$	10,612	$	11,100	$	10,550	$	9,675	$	9,050	$	9,650	$	50,025

(1) *Amounts include AFUDC debt or capitalized interest*
(2) *Includes nuclear fuel of ~$2.1B from 2019-2023*
(3) *2018 actual amounts include ~$500 million in coal ash closure spending that was included in operating cash flows*
(4) *Amounts are net of assumed tax equity financings*
(5) *Investment level will depend upon how the project and Duke investment are financed; 2018 actual amounts include $460 million funded under the ACP revolving credit facility*
(6) *Primarily IT and real estate related costs*

Capital expenditures by utility[(1)]

($ in millions)

Duke Energy Carolinas	2018A	2019E	2020E	2021E	2022E	2023E	2019 - 2023
Electric Generation	$488	$525	$575	$500	$500	$950	$3,050
Electric Transmission	131	225	225	175	175	175	$975
Electric Distribution	675	675	825	775	800	900	$3,975
Environmental & Other [(2)]	561	450	375	300	150	125	$1,400
Duke Energy Carolinas Growth Capital	$ 1,854	$ 1,875	$ 2,000	$ 1,750	$ 1,625	$ 2,150	$ 9,400
Maintenance	1,077	875	725	825	875	1,125	4,425
Total Duke Energy Carolinas Capital	$ 2,930	$ 2,750	$ 2,725	$ 2,575	$ 2,500	$ 3,275	$ 13,825

Duke Energy Progress	2018A	2019E	2020E	2021E	2022E	2023E	2019 - 2023
Electric Generation	$820	$475	$325	$475	$725	$625	$2,625
Electric Transmission	99	125	150	150	375	175	$975
Electric Distribution	409	500	600	600	650	625	$2,975
Environmental & Other [(3)]	442	550	300	150	150	125	$1,275
Duke Energy Progress Growth Capital	$ 1,770	$ 1,650	$ 1,375	$ 1,375	$ 1,900	$ 1,550	$ 7,850
Maintenance	645	700	425	500	425	525	2,575
Total Duke Energy Progress Capital	$ 2,415	$ 2,350	$ 1,800	$ 1,875	$ 2,325	$ 2,075	$ 10,425

(1) Amounts include AFUDC debt
(2) 2018 actual amounts include ~$230 million in coal ash closure spending that was included in operating cash flows
(3) 2018 actual amounts include ~$195 million in coal ash closure spending that was included in operating cash flows

Capital expenditures by utility (continued)[1]

($ in millions)

Duke Energy Florida		2018A		2019E		2020E		2021E		2022E		2023E		2019 - 2023
Electric Generation		$403		$425		$300		$475		$100		$100		$1,400
Electric Transmission		308		400		550		475		550		500		2,475
Electric Distribution		220		525		500		525		500		450		2,500
Environmental & Other		48		-		-		-		-		-		$0
Duke Energy Florida Growth Capital	$	978	$	1,350	$	1,350	$	1,475	$	1,150	$	1,050	$	6,375
Maintenance		656		450		350		300		300		375		1,775
Total Duke Energy Florida Capital	$	1,634	$	1,800	$	1,700	$	1,775	$	1,450	$	1,425	$	8,150

Duke Energy Indiana		2018A		2019E		2020E		2021E		2022E		2023E		2019 - 2023
Electric Generation		$74		$100		$125		$50		$50		$25		$350
Electric Transmission		202		125		150		150		150		150		725
Electric Distribution		237		300		250		225		225		225		1,225
Environmental & Other [2]		105		125		150		100		75		75		525
Duke Energy Indiana Growth Capital	$	618	$	650	$	675	$	525	$	500	$	475	$	2,825
Maintenance		280		250		225		150		175		325		1,125
Total Duke Energy Indiana Capital	$	898	$	900	$	900	$	675	$	675	$	800	$	3,950

(1) *Amounts include AFUDC debt*
(2) *2018 actual amounts include ~$65 million in coal ash closure spending that was included in operating cash flows*

DUKE ENERGY.

Capital expenditures by utility (continued)[1]

($ in millions)

Duke Energy OH/KY Electric	2018A	2019E	2020E	2021E	2022E	2023E	2019 - 2023
Electric Generation	$38	$25	$50	$75	$50	$25	$225
Electric Transmission	174	175	125	100	75	75	550
Electric Distribution	289	375	325	325	325	325	1,675
Environmental & Other[2]	45	25	25	25	-	-	75
Duke Energy OH/KY Growth Capital	$545	$600	$525	$525	$450	$425	$2,525
Maintenance	151	100	75	25	50	75	325
Total Duke Energy OH/KY Electric Capital	$696	$700	$600	$550	$500	$500	$2,850

Duke Energy OH/KY Gas	2018A	2019E	2020E	2021E	2022E	2023E	2019 - 2023
LDC - Non-Rider	$50	$50	$100	$125	$25	$0	$300
LDC - Rider	11	-	-	-	-	-	-
Duke Energy OH/KY Gas Growth Capital	$61	$50	$100	$125	$25	$0	300
Maintenance	110	150	125	125	125	100	625
Total Duke Energy OH/KY Gas Capital	$172	$200	$225	$250	$150	$100	$925

Piedmont	2018A	2019E	2020E	2021E	2022E	2023E	2019 - 2023
LDC - Non-Rider	$227	$600	$350	$225	$250	$250	$1,675
LDC - Rider	254	275	200	225	200	275	1,175
Piedmont Growth Capital	$481	$875	$550	$450	$450	$525	2,850
Maintenance	240	125	125	125	50	75	500
Total Piedmont Capital	$721	$1,000	$675	$575	$500	$600	$3,350

(1) *Amounts include AFUDC debt*
(2) *2018 actual amounts include ~$5 million in coal ash closure spending that was included in operating cash flows*

Environmental compliance expenditures

($ in millions)

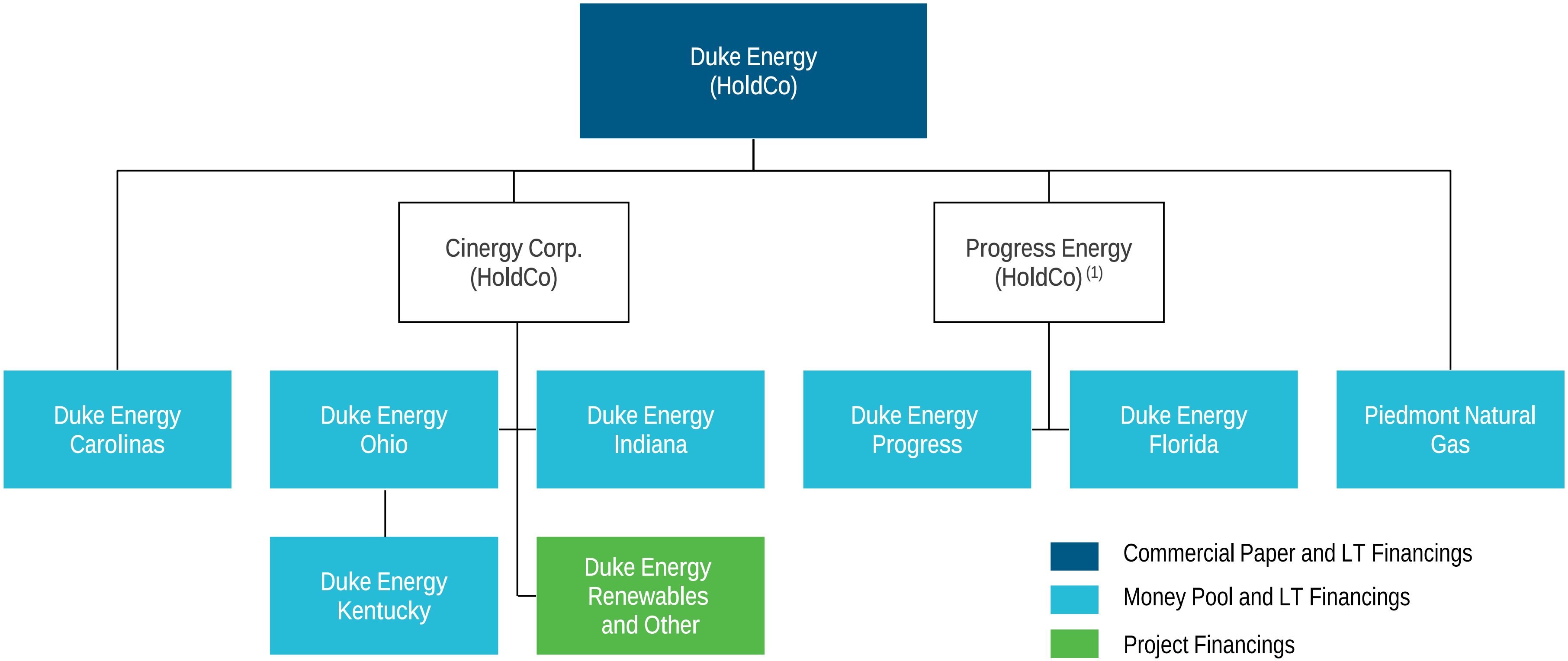
Category	2019 – 2023
Waste (closure)	$2,380
All other environmental	$400
Total	$2,780

Coal Ash Closure Costs	Total Project Costs	Spend To Date[(1)]	2019 – 2023 Plan
Duke Energy Carolinas	$2,760	$950	$730
Duke Energy Progress	$2,900	$700	$1,190
Duke Energy Indiana	$930	$150	$425
Duke Energy Florida	$25	--	$5
Duke Energy Kentucky	$75	$15	$30
Total	$6,690	$1,815	$2,380

(1) As of Dec. 31, 2018

Financing assumptions

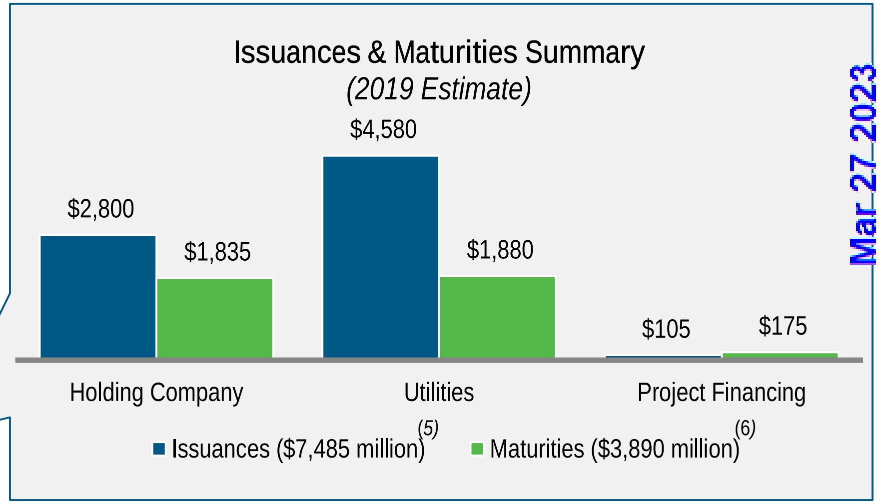
Simplified financing structure



(1) Progress Energy HoldCo has long-term debt outstanding, but no future issuance is planned at this financing entity

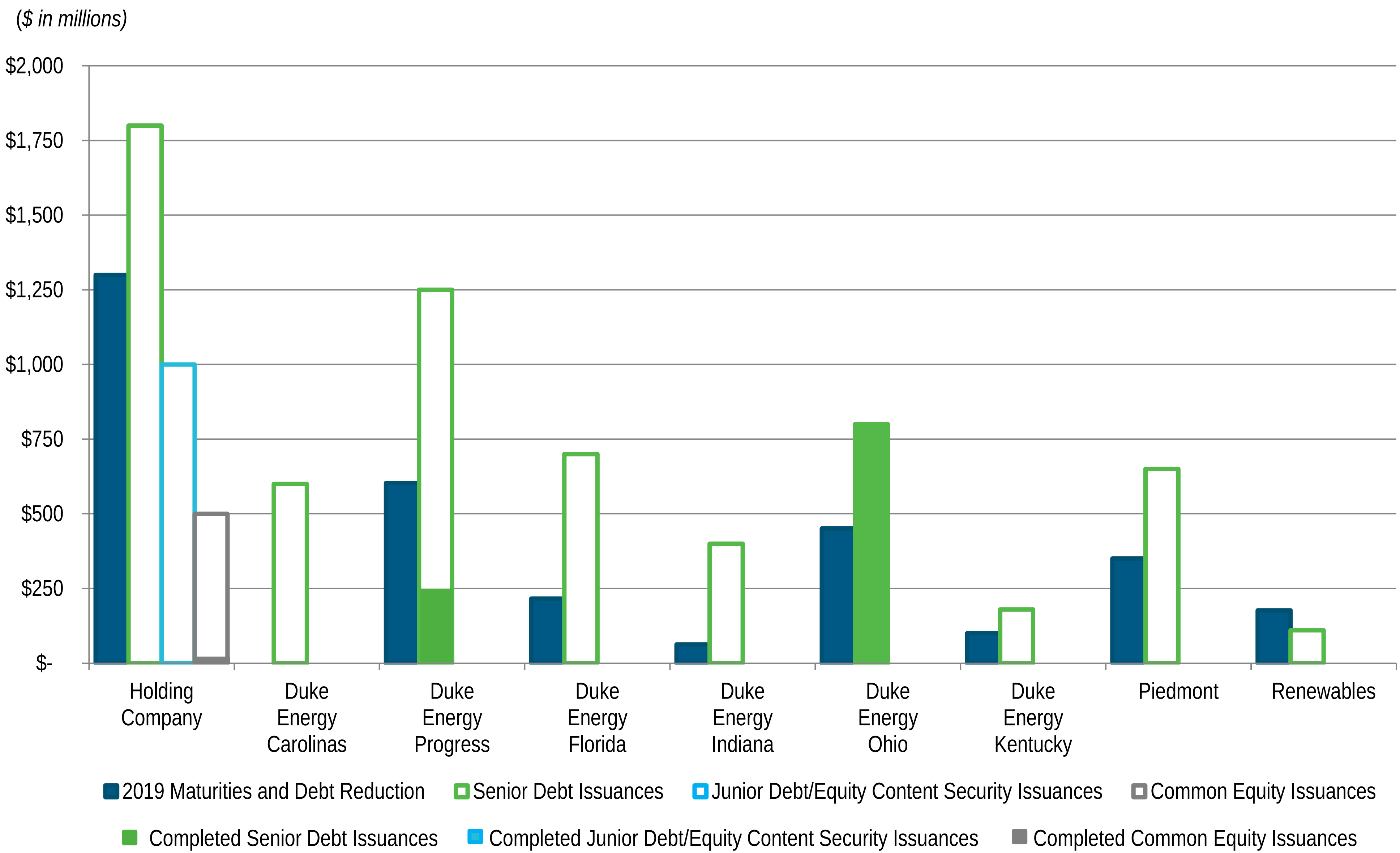
Forecasted 2019 summary cash flows[1]

Adjusted net income[2]	$ 3,645
Depreciation & amortization	4,970
Deferred and accrued taxes[3]	1,260
Other sources / (uses), net[4]	(340)
Primary sources	**9,535**
Capital expenditures	(11,100)
Dividends (subject to Board of Directors discretion)	(2,750)
Primary uses	**(13,850)**
Uses in excess of sources	(4,315)
Net Change in debt	3,595
Common equity issuance	500
Net Change in Cash	**(220)**



(1) Financing plan subject to change, based on circumstances encountered throughout the year
(2) Based upon the midpoint of the 2019 guidance range as presented on the in the Fourth Quarter 2018 Earnings Review and Business Update on Feb. 14, 2019
(3) Includes expected AMT refund of $575 million
(4) Includes changes in working capital and AFUDC equity
(5) Includes junior subordinated debt/equity content security issuances
(6) Includes net changes in Commercial Paper

2019 financing plan[1]



(1) *Financing plan subject to change, based on circumstances encountered throughout the year. Represents expected long-term debt and common equity capital raising during 2019*

Liquidity summary (as of Dec. 31, 2018)

($ in millions)

	Duke Energy	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio	Duke Energy Kentucky	Piedmont Natural Gas	Total
Master Credit Facility [1]	$ 2,650	$ 1,750	$ 1,400	$ 650	$ 600	$ 300	$ 150	$ 500	$ 8,000
Less: Notes payable and commercial paper [2]	(917)	(739)	(444)	(108)	(317)	(235)	(64)	(198)	(3,022)
Coal Ash Set-Aside	-	(250)	(250)	-	-	-	-	-	(500)
Outstanding letters of credit (LOCs)	(45)	(4)	(2)	-	-	-	-	(2)	(53)
Tax-exempt bonds	-	-	-	-	(81)	-	-	-	(81)
Available capacity	$ 1,688	$ 757	$ 704	$ 542	$ 202	$ 65	$ 86	$ 300	$ 4,344
Funded Revolver and Term Loan [3]	$ 1,000		$ 700						$ 1,700
Less: Borrowings Under Credit Facilities	(500)		(50)						(550)
Available capacity	$ 500	$ -	$ 650	$ -	$ -	$ -	$ -	$ -	$ 1,150
Cash & short-term investments									368
Total available liquidity									$ 5,862

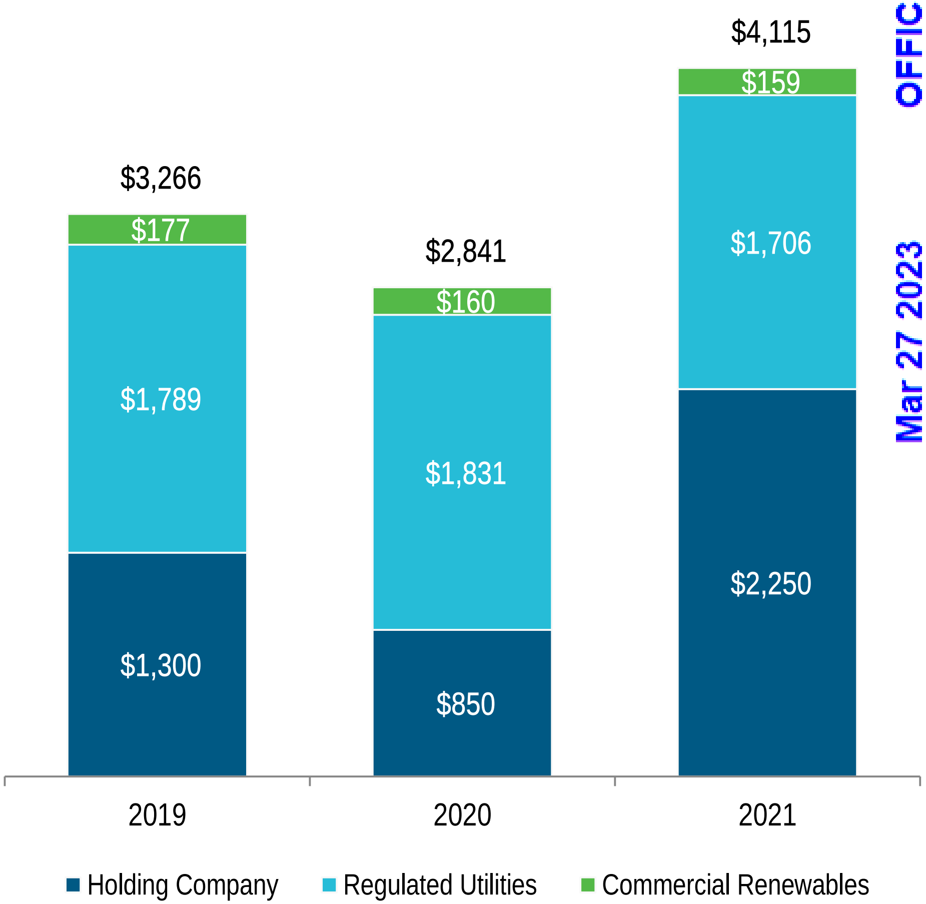
(1) Master Credit Facility supports tax-exempt put bonds, LOCs and the Duke Energy commercial paper program of $4.85 billion
(2) Includes permanent layer of commercial paper of $625 million, which is classified as long-term debt
(3) Borrowings under these facilities will be used for general corporate purposes.
(4) Excludes variable denomination floating-rate demand notes, called PremierNotes. At 12/31/2018, the PremierNotes balance was $1,010 million.

Long-term debt maturities(1)

Regulated Utilities Maturities Detail

($ in millions)

	2019	2020	2021
Duke Energy Carolinas (2)	$ 6	$ 457	$ 503
Duke Energy Progress (2)	603	354	604
Duke Energy Florida (2) (3)	216	517	319
Duke Energy Indiana	63	503	70
Duke Energy Ohio	451	-	-
Duke Energy Kentucky	100	-	50
Piedmont Natural Gas	350	-	160
Regulated Utilities	$ 1,789	$ 1,831	$ 1,706



(1) Schedule for long-term debt outstanding at Dec. 31, 2018. Excludes amortization of noncash purchase accounting adjustments
(2) Excludes securitized receivables credit facilities maturing in 2020 and 2021 which are expected to be renewed
(3) Excludes amortization of CR3 securitization

Credit ratings (as of Feb. 28, 2019)

Holding Companies

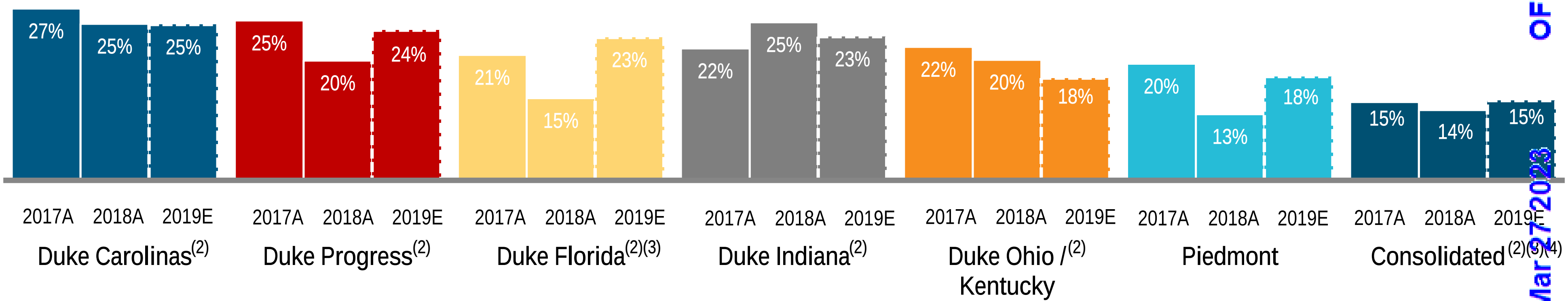
	Moody's	S&P	Fitch
DUKE ENERGY CORPORATION	Stable	Stable	Stable
Senior Unsecured Debt	Baa1	BBB+	BBB+
Commercial Paper	P-2	A-2	F-2
PROGRESS ENERGY, INC.	Stable	Stable	
Senior Unsecured Debt	Baa1	BBB+	

Operating Companies

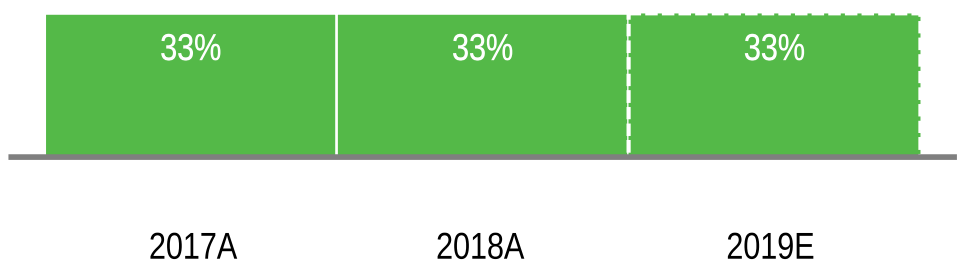
	Moody's	S&P
DUKE ENERGY CAROLINAS, LLC	Stable	Stable
Senior Secured Debt	Aa2	A
Senior Unsecured Debt	A1	A-
DUKE ENERGY PROGRESS, LLC	Stable	Stable
Senior Secured Debt	Aa3	A
DUKE ENERGY FLORIDA, LLC	Stable	Stable
Senior Secured Debt	A1	A
Senior Unsecured Debt	A3	A-
DUKE ENERGY INDIANA, LLC	Stable	Stable
Senior Secured Debt	Aa3	A
Senior Unsecured Debt	A2	A-
DUKE ENERGY OHIO, INC.	Stable	Stable
Senior Secured Debt	A2	A
Senior Unsecured Debt	Baa1	A-
DUKE ENERGY KENTUCKY, INC.	Stable	Stable
Senior Unsecured Debt	Baa1	A-
PIEDMONT NATURAL GAS, INC.	Stable	Stable
Senior Unsecured Debt	A3	A-

Credit metrics[1]

FFO/Debt



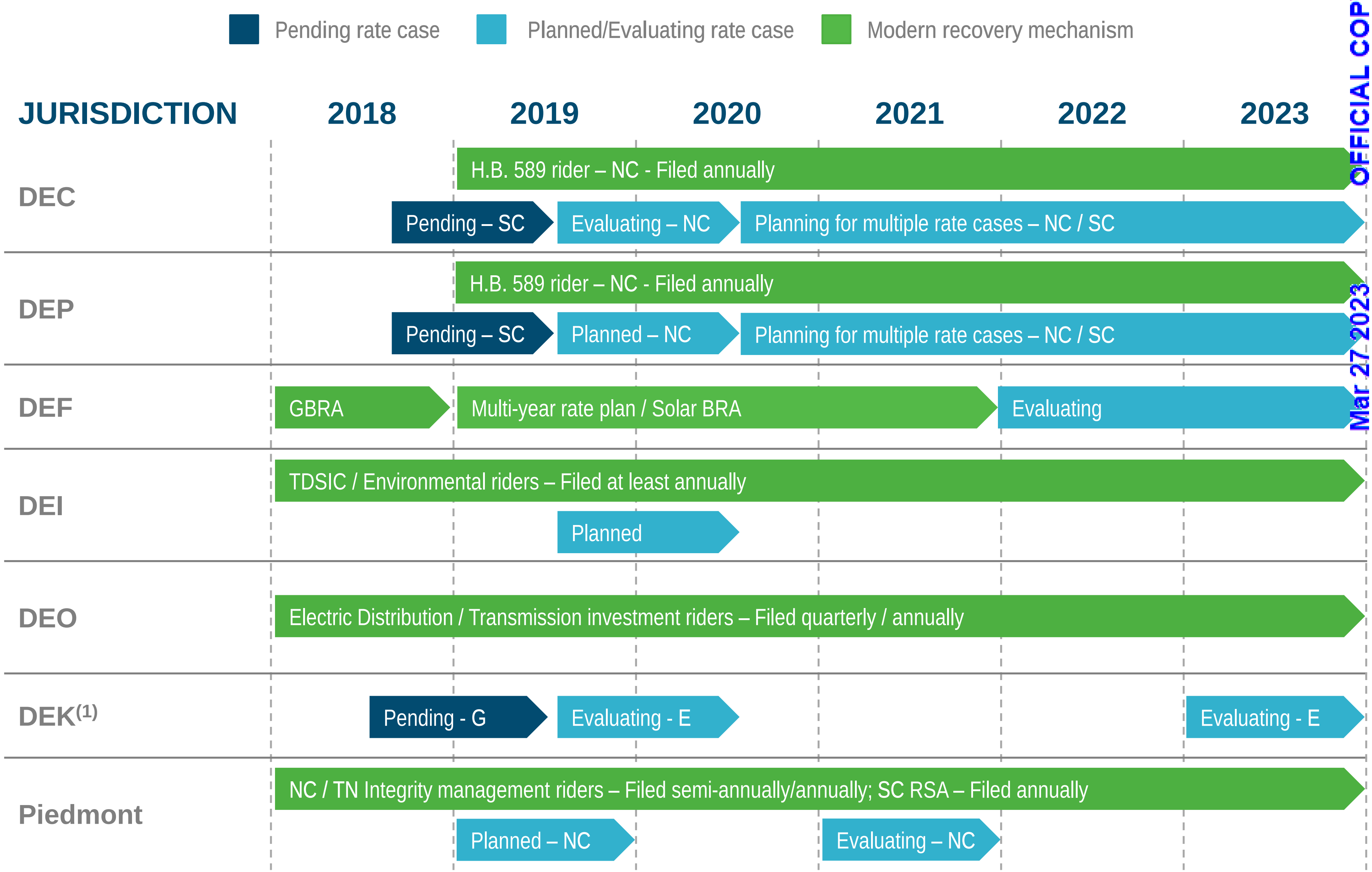
HoldCo Debt / Total Debt



(1) *Amounts do not include all adjustments that may be made by the rating agencies*
(2) *Excludes coal ash/ARO spend*
(3) *Assumes CR-3 securitization treated as off credit*
(4) *Consolidated metrics exclude increases to debt associated with purchase accounting*

Regulatory overview

Regulatory calendar



(1) "E" denotes Electric, "G" denotes Gas

DEP and DEC South Carolina rate case details

	Duke Energy Progress	Duke Energy Carolinas
Retail revenue increase requested	$59 M (+10.3%)	$168 M (+10.0%)
Return on equity requested	10.5%	
Equity component of capital structure	53%	
Proposed rate base[1]	$1.5 B	$5.6 B
Rates requested to be in effect, if approved	June 1, 2019	
Drivers	**% of Total Request**	
Significant plant additions and changes	97%	149%
Coal ash related compliance costs	22%	37%
Reduction due to federal tax reform and change in N.C. state tax	(25%)	(77%)
All other changes to rate base, operating costs and operating revenues	7%	(10%)

(1) As of Dec. 31, 2017 and adjusted for known and measurable changes through Dec. 2018

Overview of state commissions by jurisdiction

	North Carolina	South Carolina	Florida	Indiana	Ohio	Kentucky	Tennessee
Number of Commissioners	7	7	5	5	5	3	5
Term	6-year terms	4-year terms	4-year terms	4-year terms	5-year terms	4-year terms	6-year terms
Appointed/ Elected	Appointed by Governor	Elected by the General Assembly	Appointed by Governor	Appointed by Governor	Appointed by Governor	Appointed by Governor	Appointed by Governor and Legislature
Chair *(Term Exp.)*	Ed Finley *(June 2019)*	Randy Randall *(June 2020)*	*Art Graham *(January 2022)*	Jim Huston *(March 2021)*	Asim Haque(3) *(April 2021)*	Michael Schmitt *(June 2019)*	Robin Morrison *(June 2020)*
Other Commissioners *(Term Exp.)*	▪ Jerry Dockham *(June 2019)* ▪ James Patterson *(June 2019)* ▪ Lyons Gray *(June 2021)* ▪ ToNola Brown-Bland *(June 2023)* ▪ Dan Clodfelter *(June 2023)* ▪ Charlotte Mitchell *(June 2023)*	▪ Elliott Elam *(June 2018)*(1) ▪ Swain Whitfield *(June 2020)* ▪ Butch Howard *(June 2020)* ▪ G. O' Neal Hamilton *(June 2020)* ▪ Tom Ervin *(June 2022)* ▪ Justin Williams *(June 2022)*	▪ Julie Brown *(January 2023)*(2) ▪ Donald Polmann *(January 2021)* ▪ Gary Clark(1) *(January 2023)*(2) ▪ Andrew Fay *(January 2022)*	▪ David Ziegner *(April 2019)* ▪ David Ober *(January 2020)* ▪ Sarah Freeman *(January 2022)* ▪ Stefanie Krevda *(April 2022)*	▪ Lawrence Friedman *(April 2020)* ▪ Beth Trombold *(April 2023)* ▪ Thomas Johnson(3) *(April 2019)* ▪ Daniel Conway *(April 2022)*	▪ Robert Cicero *(June 2020)* ▪ Talina Mathews *(June 2021)*	▪ Kenneth Hill *(June 2020)* ▪ Herbert Hilliard *(June 2023)* ▪ John Hie *(June 2024)* ▪ David Jones *(June 2024)*

**Being considered for appointment to FERC*
(1) Serving in holdover status until S.C. General Assembly elects new commissioner
(2) If confirmed during 2019 session
(3) Asim Haque announced resignation effective Mar. 1, 2019; Governor appointed Sam Randazzo to replace Thomas Johnson and serve as next Chair of Commission effective Apr. 1, 2019, subject to confirmation by the Ohio Senate.

Current electric rate information by jurisdiction

	North Carolina	South Carolina	Florida	Indiana	Ohio (Electric)	Kentucky (Electric)
Retail Rate Base	$13.5 B [(1)] (DEC) $8.2 B [(1)] (DEP)	$4.2 B [(1)] (DEC) $1.3 B [(1)] (DEP)	$12.6B [(2)]	$7.1 B [(3)]	$1.3 B	$650 M [(4)]
Wholesale Rate Base	$1.6 B (DEC) 3Q 2018 $3.1 B (DEP) 3Q 2018		$1.4 B [(2)]	$550 M	$0.5 B (trans. only)	$0
Allowed ROE	9.9% (DEC & DEP)	10.20% (DEC) 10.10% (DEP)	10.50% [(5)]	10.50%	9.84% - Dist 11.38% - Trans	9.725%
Allowed Equity	52.0% (DEC & DEP)	53.0% (DEC & DEP)	44.34% [(6)]	44.44% [(7)]	50.8%	49.3%
Effective Date of Most Recent Rates	8/1/18 (DEC) 3/16/18 (DEP)	9/17/13 (DEC) 1/1/17 (DEP)	1/1/19	5/24/04	Distr: 1/2/19 Trans 6/1/18 ESP: 1/2/19	4/13/18
Fuel Clause Updated	Annually (DEC and DEP)	Annually (DEC and DEP)	Annually	Quarterly	Annually for Non-Shoppers	Monthly
Environmental Clause Updated	N/A	N/A	Annually	Semi-Annually	Quarterly	Monthly

(1) DEC NC's rate base as of August 2018. DEC SC's as of September 2013. DEP NC's rate base as of March 2018. DEP SC's as of December 2016.
(2) Thirteen-month average as of November 2018. Retail rate base includes amounts recovered in base rates of $11.7B and amounts recovered in trackers of $0.9B.
(3) As of Dec. 31, 2018; includes amounts being recovered in base rates of $3.7B, amounts being recovered in environmental trackers of $1.1B, and amounts being recovered in IGCC trackers of $2.1B
(4) Kentucky allows recovery on total capitalization instead of rate base
(5) Represents the mid-point of an authorized range from 9.5% to 11.5%
(6) Florida's capital structure includes accumulated deferred income taxes (ADIT), customer deposits and investment tax credits (ITC) and is as of Nov. 30, 2018. Excluding these items, the capital structure approximates 53% equity
(7) Indiana's capital structure includes ADIT. When ADIT is excluded, resulting cap structure approximates 53% equity

Current electric rate information by jurisdiction (continued)

General Rate Case Provisions

	North Carolina	South Carolina	Florida	Indiana	Ohio (Electric)	Kentucky (Electric)
Notice of Intent Required?	Yes	Yes	Yes	Yes [(1)]	Yes	Yes
Notice Period	30 Days	30 Days	60 Days	Varies	30 Days	28 Days
Test Year	Historical Adjusted for Known and Measureable Changes	Historical Adjusted for Known and Measureable Changes	Projected	Optional [(2)]	Partially Projected	Forecast Optional
Time Limitation Between Cases	No	12 months [(3)]	No	15 Months	No	No
Rates Effective Subject to Refund	9 Months After Filing	6 Months After Filing [(4)]	8 Months After Filing	10 Months After Filing [(5)]	9 Months After Filing	6 Months After Filing [(6)]

(1) *IURC recommended procedure. Not a statutory requirement*
(2) *Utilities may elect to a historical test period, a forward-looking test period, or a hybrid test year in the context of a general rate case*
(3) *Our current settlement from the 2016 rate case in DEP SC precludes implementing new rates until 2019*
(4) *If the South Carolina Commission fails to rule on a rate case filing within 6 months, the new rates can be implemented and are not subject to refund. There is a grace period here. The Company would have to notify the Commission that it planned to put rates in and the Commission would then have 10 additional days to issue an order*
(5) *The utility may implement interim rates, subject to refund, if the IURC has not rendered a decision within 10 months of filing (can be extended 60 days by IURC). The interim rates are not to exceed 50% of the original request*
(6) *The effective date is 7 months after filing for a forecasted test year*

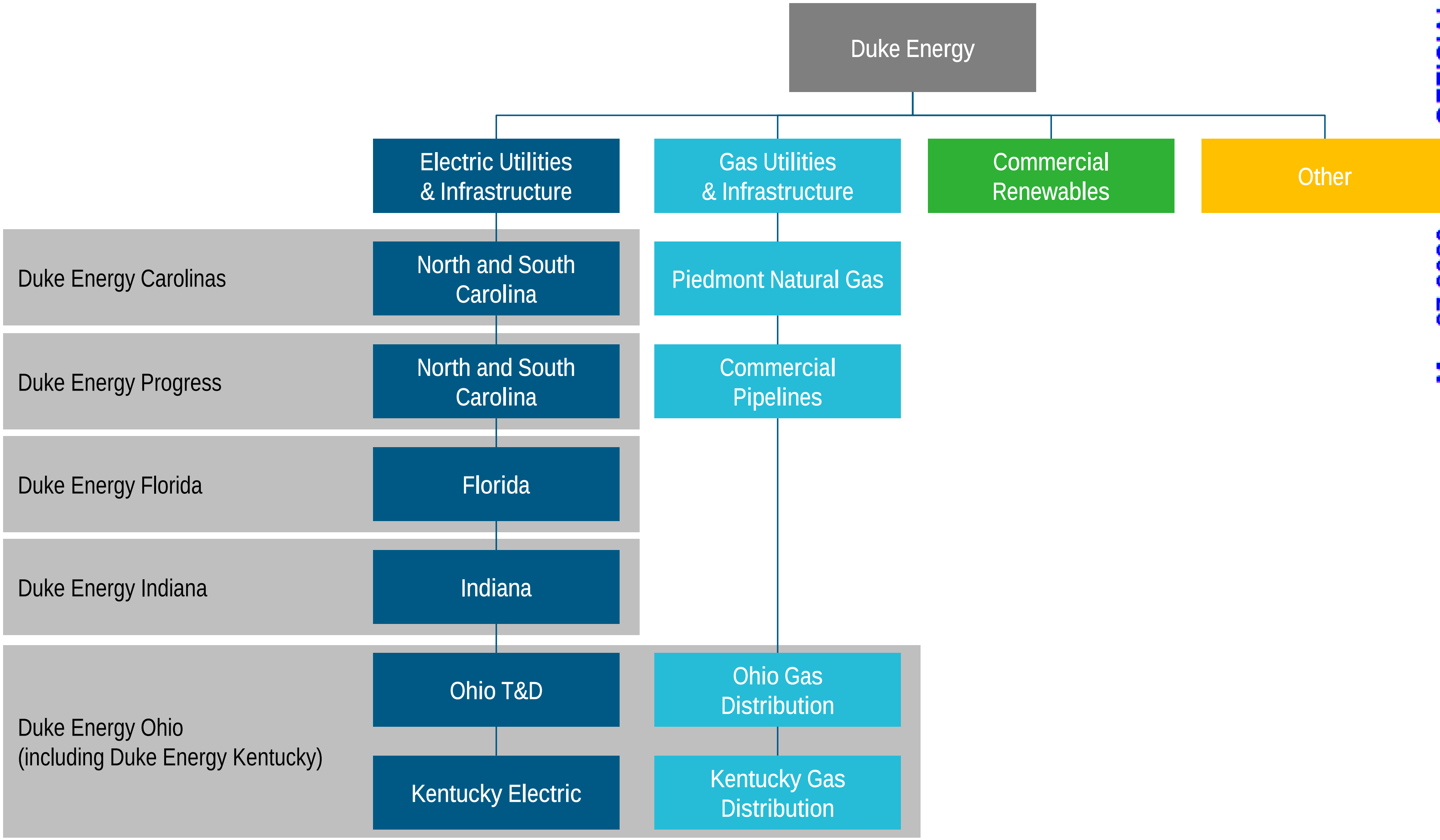
Current gas rate information by jurisdiction

	North Carolina	South Carolina	Tennessee	Ohio (Gas)	Kentucky (Gas)
Rate Base ($M)	$1,822	$341	$349	$900 (1)	$250 (2)
Allowed ROE	10.0%	10.2%	10.2%	9.84%	10.38%
Allowed Equity	50.7%	53.0%	52.7%	53.3%	50.8%
Effective Date of Most Recent Rates	1/1/14	11/1/18 (3)	3/1/12	12/1/13	1/1/10
Significant Rider Mechanisms	Margin Decoupling Rider Integrity Management Rider Fuel Clause	Rate Stabilization Adj. Weather Normalization Adj. Fuel Clause	Weather Normalization Adj. Integrity Management Rider Fuel Clause	AMRP SmartGrid Fuel Clause	ASRP (4) Fuel Clause

(1) Excludes all rate base related to capital recovery that is being tracked (e.g., AMRP and AU after 3/31/2012)
(2) Kentucky allows recovery on total capitalization instead of rate base
(3) Rates refreshed annually under the South Carolina Rate Stabilization Act (RSA)
(4) Recovers incremental costs for the Accelerated Service Line Replacement (ASRP) Program

Segment overviews

Duke Energy business segment structure



Electric utilities & infrastructure

EIGHT UTILITIES IN HIGH-QUALITY REGIONS OF THE U.S.

CAROLINAS

Duke Energy Carolinas (NC/SC)

Duke Energy Progress (NC/SC)

FLORIDA

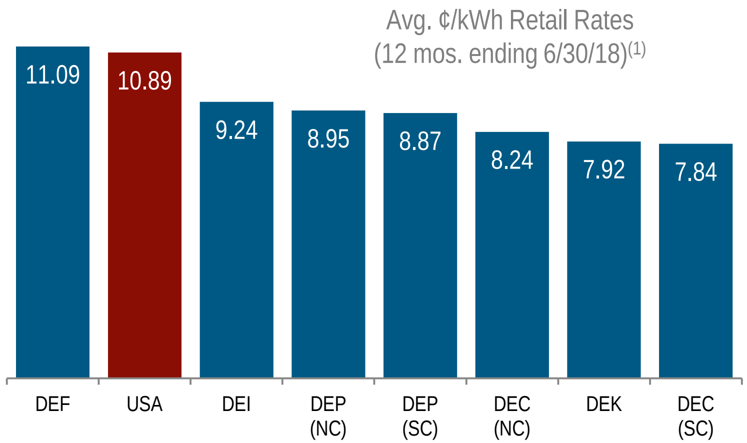
Duke Energy Florida

MIDWEST

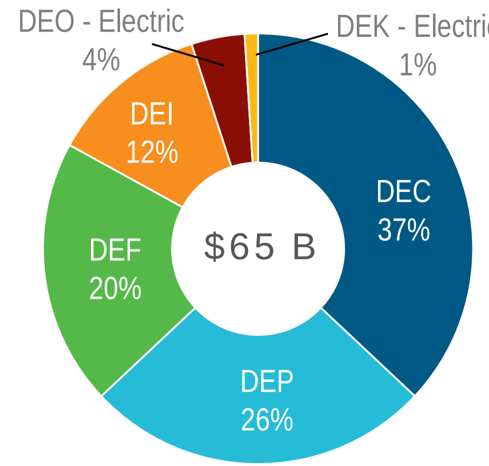
Duke Energy Indiana

Duke Energy Ohio / Kentucky

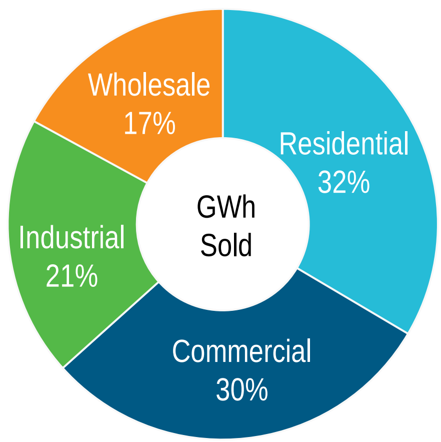
COMPETITIVE CUSTOMER RATES



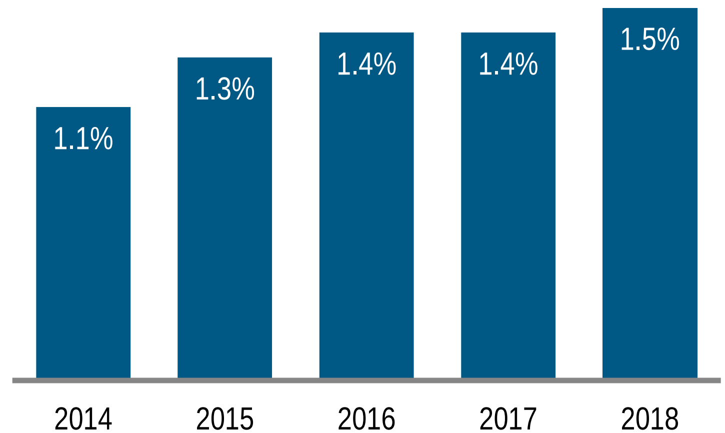
REGULATED ELECTRIC 2018 EARNINGS BASE



BALANCED CUSTOMER MIX

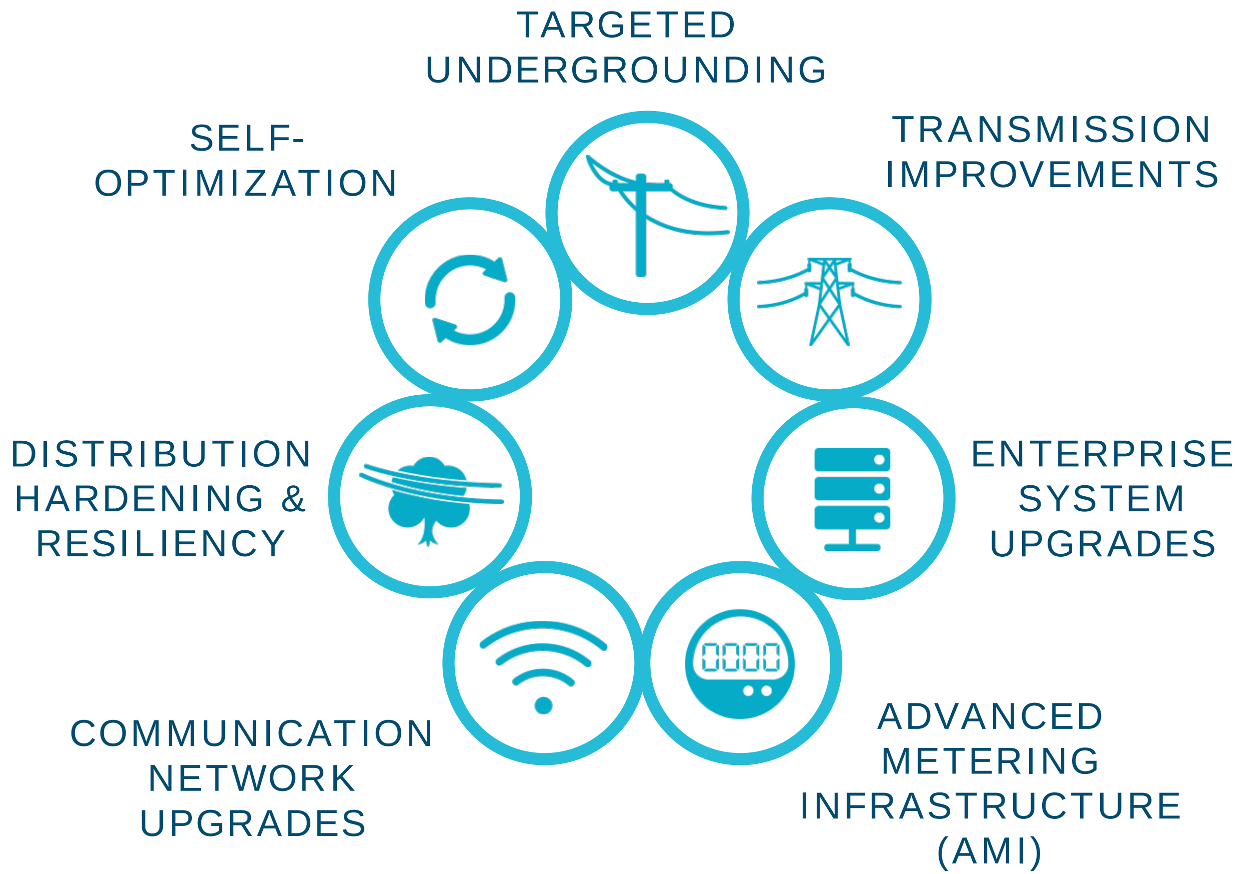


STRONG RESIDENTAL CUSTOMER GROWTH



(1) *Vertically integrated utilities only. Source: EEI Typical Bills and Avg. Rates Report Summer 2018*

Grid improvement programs overview

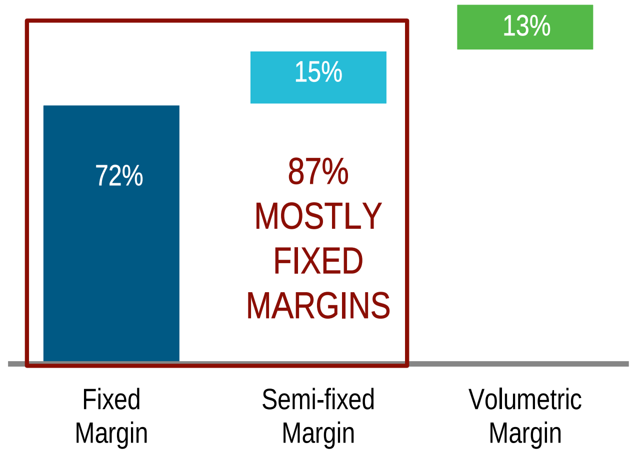


CUSTOMER BENEFITS

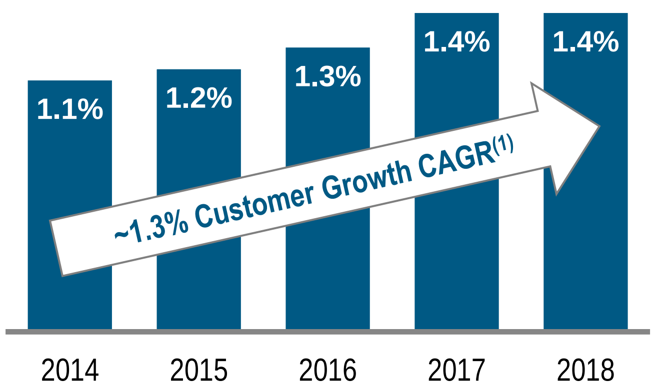
Increased reliability	Provide information customers value	Enable distributed generation	Improve cyber and physical security

Gas utilities & infrastructure

GAS UTILITIES WITH LOW VOLUMETRIC EXPOSURE DUE TO MOSTLY FIXED MARGINS…



…WITH EARNINGS DRIVEN BY INVESTMENT AND STRONG RESIDENTIAL CUSTOMER GROWTH



MARGIN STABILIZING MECHANISMS

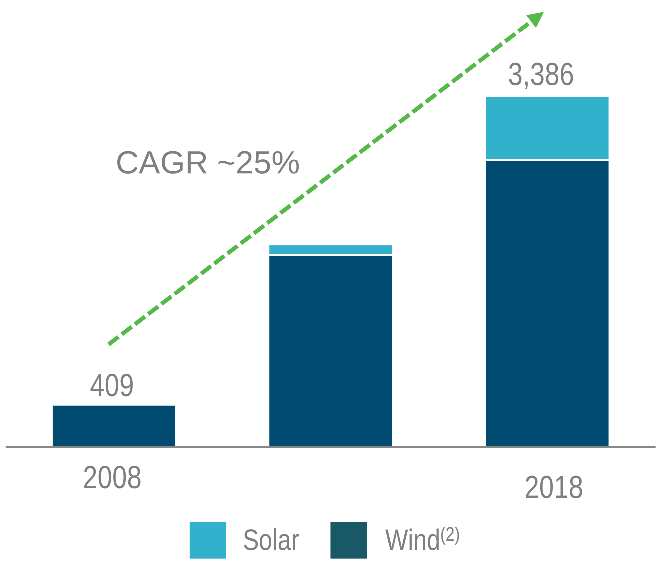
1. Purchased Gas Adjustment	All States
2. Uncollectible Recovery	All States
3. Integrity Management Rider ("IMR")	North Carolina and Tennessee
4. Margin Decoupling	North Carolina
5. Weather Normalization	South Carolina and Tennessee
6. Rate Stabilization Act	South Carolina
7. Accelerated Meter Replacement Program Rider	Ohio
8. Advanced Utility Rider	Ohio
9. Manufactured Gas Rider	Ohio

(1) *Piedmont CAGR: 1.6%, Midwest LDC CAGR 0.7%*

Commercial Renewables

RAPID GROWTH FROM PROJECT DEVELOPMENT

(GROSS MW CAPACITY)(1)



LARGE SCALE BUSINESS WITH INDUSTRY-LEADING OPERATING EXPERTISE

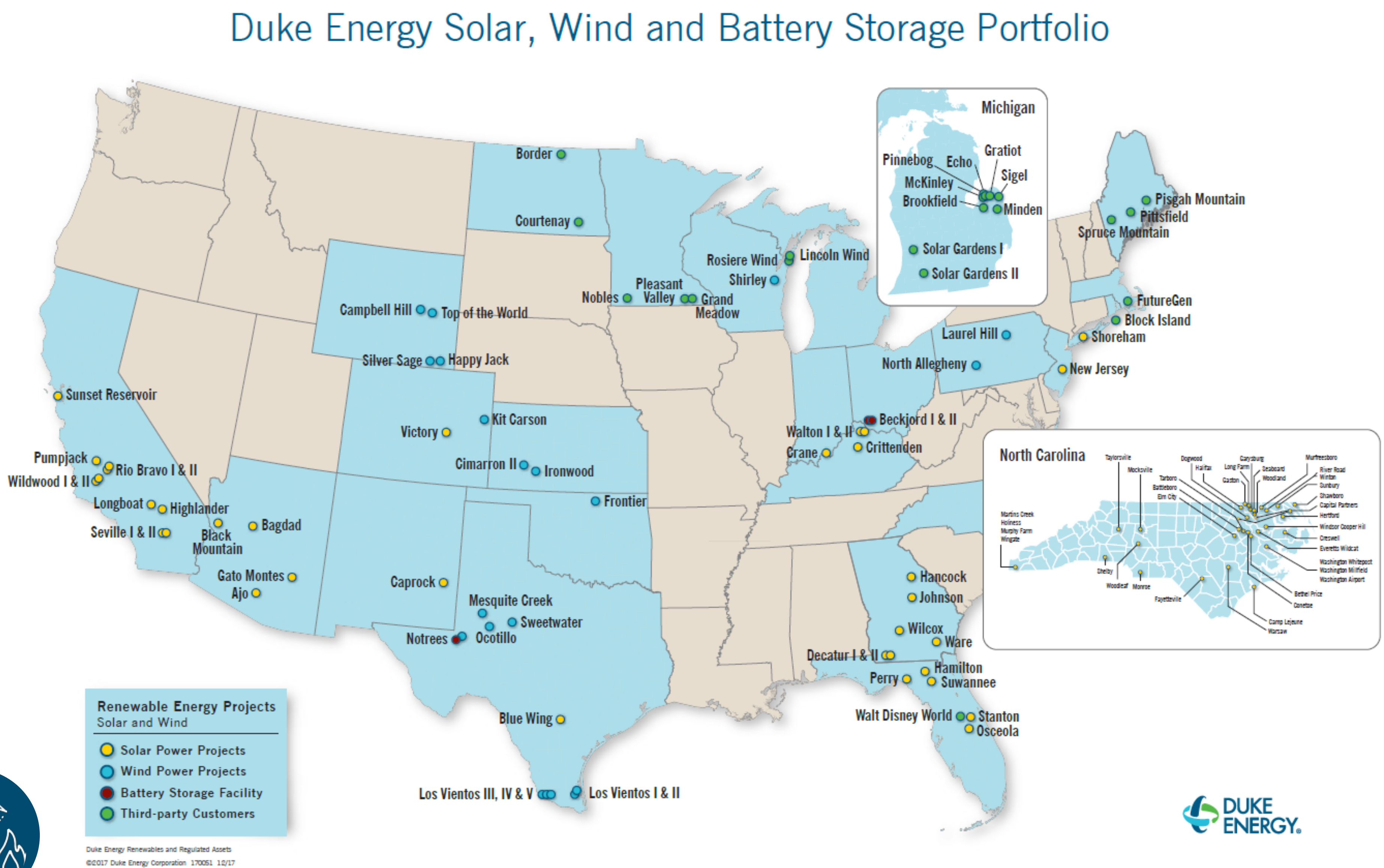
- Top-ten owner of wind and solar in the U.S., with ~3,400 MW of operating projects and ~$5 billion invested
- Duke Energy Renewable Services – wholly-owned O&M services provider for Duke and third-party assets
  - ~4,100 MW of wind and ~600 MW of solar
  - Renewable Control Center provides 24/7 monitoring services

HIGHLY VISIBLE GROWTH

- Successfully pivoted to utilizing tax equity financing
- Line of sight to strong demand from IRS tax credit safe harbor guidance
- Over 1,000 MW of wind and solar projects in late stages of development
  - Announced 100 MW Lapetus solar project
- Recycling capital through minority stake sale process

(1) Total project capacity. Certain projects Duke owns <100%
(2) Includes the Notrees battery storage project and excludes Sweetwater 1-3 projects that have been sold

Commercial and regulated renewables asset locations(1)



(1) *A full list of generation facilities can be found at https://www.duke-energy.com//_/media/pdfs/our-company/investors/duke-energy-generation-portfolio.pdf*

Upcoming events & other

Upcoming events

Event	Date
1Q 2019 earnings call (tentative)	May 9, 2019
2Q 2019 earnings call (tentative)	August 6, 2019
3Q 2019 earnings call (tentative)	November 8, 2019

Investor relations contact information

MIKE CALLAHAN, VICE PRESIDENT INVESTOR RELATIONS

- Michael.Callahan@duke-energy.com
- (704) 382-0459

MIKE SWITZER, DIRECTOR INVESTOR RELATIONS

- Mike.Switzer@duke-energy.com
- (704) 382-6473

ABBY MOTSINGER, MANAGER INVESTOR RELATIONS

- Abby.Motsinger@duke-energy.com
- (704) 382-7624

Safe harbor statement

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions and can often be identified by terms and phrases that include "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," "target," "guidance," "outlook" or other similar terminology. Various factors may cause actual results to be materially different than the suggested outcomes within forward-looking statements; accordingly, there is no assurance that such results will be realized. These factors include, but are not limited to: State, federal and foreign legislative and regulatory initiatives, including costs of compliance with existing and future environmental requirements, including those related to climate change, as well as rulings that affect cost and investment recovery or have an impact on rate structures or market prices; The extent and timing of costs and liabilities to comply with federal and state laws, regulations and legal requirements related to coal ash remediation, including amounts for required closure of certain ash impoundments, are uncertain and difficult to estimate; The ability to recover eligible costs, including amounts associated with coal ash impoundment retirement obligations and costs related to significant weather events, and to earn an adequate return on investment through rate case proceedings and the regulatory process; The costs of decommissioning Crystal River Unit 3 and other nuclear facilities could prove to be more extensive than amounts estimated and all costs may not be fully recoverable through the regulatory process; Costs and effects of legal and administrative proceedings, settlements, investigations and claims; Industrial, commercial and residential growth or decline in service territories or customer bases resulting from sustained downturns of the economy and the economic health of our service territories or variations in customer usage patterns, including energy efficiency efforts and use of alternative energy sources, such as self-generation and distributed generation technologies; Federal and state regulations, laws and other efforts designed to promote and expand the use of energy efficiency measures and distributed generation technologies, such as private solar and battery storage, in Duke Energy service territories could result in customers leaving the electric distribution system, excess generation resources as well as stranded costs; Advancements in technology; Additional competition in electric and natural gas markets and continued industry consolidation; The influence of weather and other natural phenomena on operations, including the economic, operational and other effects of severe storms, hurricanes, droughts, earthquakes and tornadoes, including extreme weather associated with climate change; The ability to successfully operate electric generating facilities and deliver electricity to customers including direct or indirect effects to the company resulting from an incident that affects the U.S. electric grid or generating resources; The ability to obtain the necessary permits and approvals and to complete necessary or desirable pipeline expansion or infrastructure projects in our natural gas business; Operational interruptions to our natural gas distribution and transmission activities; The availability of adequate interstate pipeline transportation capacity and natural gas supply; The impact on facilities and business from a terrorist attack, cybersecurity threats, data security breaches, operational accidents, information technology failures or other catastrophic events, such as fires, explosions, pandemic health events or other similar occurrences; The inherent risks associated with the operation of nuclear facilities, including environmental, health, safety, regulatory and financial risks, including the financial stability of third-party service providers; The timing and extent of changes in commodity prices and interest rates and the ability to recover such costs through the regulatory process, where appropriate, and their impact on liquidity positions and the value of underlying assets; The results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings, interest rate fluctuations, compliance with debt covenants and conditions and general market and economic conditions; Credit ratings of the Duke Energy Registrants may be different from what is expected; Declines in the market prices of equity and fixed-income securities and resultant cash funding requirements for defined benefit pension plans, other post-retirement benefit plans and nuclear decommissioning trust funds; Construction and development risks associated with the completion of the Duke Energy Registrants' capital investment projects, including risks related to financing, obtaining and complying with terms of permits, meeting construction budgets and schedules and satisfying operating and environmental performance standards, as well as the ability to recover costs from customers in a timely manner, or at all; Changes in rules for regional transmission organizations, including changes in rate designs and new and evolving capacity markets, and risks related to obligations created by the default of other participants; The ability to control operation and maintenance costs; The level of creditworthiness of counterparties to transactions; Employee workforce factors, including the potential inability to attract and retain key personnel; The ability of subsidiaries to pay dividends or distributions to Duke Energy Corporation holding company (the Parent); The performance of projects undertaken by our nonregulated businesses and the success of efforts to invest in and develop new opportunities; The effect of accounting pronouncements issued periodically by accounting standard-setting bodies; The impact of U.S. tax legislation to our financial condition, results of operations or cash flows and our credit ratings; The impacts from potential impairments of goodwill or equity method investment carrying values; and The ability to implement our business strategy, including enhancing existing technology systems.

Additional risks and uncertainties are identified and discussed in the Duke Energy Registrants' reports filed with the SEC and available at the SEC's website at sec.gov. In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than described. Forward-looking statements speak only as of the date they are made and the Duke Energy Registrants expressly disclaim an obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

DUKE ENERGY®

BUILDING A **SMARTER** ENERGY FUTURE ®

For additional information on Duke Energy,
please visit: duke-energy.com/investors

Duke Energy Corporation
Non-GAAP Reconciliations
March 2019 Update

Adjusted Diluted Earnings per Share (EPS)

The materials for Duke Energy Corporation's (Duke Energy) March 2019 Update include a discussion of adjusted diluted EPS for the quarters and year-to-date periods ended December 31, 2018 and 2017.

The non-GAAP financial measure, adjusted diluted EPS, represents diluted EPS from continuing operations attributable to Duke Energy Corporation common stockholders, adjusted for the per share impact of special items. As discussed below, special items represent certain charges and credits, which management believes are not indicative of Duke Energy's ongoing performance.

Management believes the presentation of adjusted diluted EPS provides useful information to investors, as it provides them with an additional relevant comparison of Duke Energy's performance across periods. Management uses this non-GAAP financial measure for planning and forecasting and for reporting financial results to the Duke Energy Board of Directors (Board of Directors), employees, stockholders, analysts and investors. Adjusted diluted EPS is also used as a basis for employee incentive bonuses. The most directly comparable GAAP measure for adjusted diluted EPS is reported diluted EPS attributable to Duke Energy Corporation common stockholders. Reconciliations of adjusted diluted EPS for the quarters and year-to-date periods ended December 31, 2018 and 2017, to the most directly comparable GAAP measures are included herein.

Special items included in the periods presented include the following items, which management believes do not reflect ongoing costs:

- Costs to Achieve Piedmont Merger represents charges resulting from strategic acquisitions.
- Regulatory and Legislative Impacts in 2018 represents charges related to the Duke Energy Progress and Duke Energy Carolinas North Carolina rate case orders and the repeal of the South Carolina Base Load Review Act. For 2017, it represents charges related to the Levy nuclear project in Florida and the Mayo Zero Liquid Discharge and Sutton combustion turbine projects in North Carolina.
- Impairment Charges in 2018 represents an asset impairment at Citrus County, a goodwill impairment at Commercial Renewables and an other-than-temporary impairment of an investment in Constitution Pipeline Company, LLC. For 2017, the charges represent goodwill and other-than-temporary asset impairments at Commercial Renewables.
- Sale of Retired Plant represents the loss associated with selling Beckjord, a nonregulated generating facility in Ohio.
- Impacts of the Tax Act represents amounts recognized related to the Tax Cuts and Jobs Act.
- Severance charges relate to company-wide initiatives, excluding merger integration, to standardize processes and systems, leverage technology and workforce optimization.

Adjusted Diluted EPS Guidance

The materials for Duke Energy's March 2019 Update include a reference to forecasted 2018 adjusted diluted EPS guidance range of $4.65 - $4.85 per share, narrowed from $4.55 - $4.85 per share during the third quarter of 2018 and the forecasted 2019 adjusted diluted EPS guidance range of $4.80 - $5.20 per share. The materials also reference the long-term range of annual growth of 4% - 6% through 2023 in adjusted diluted EPS (on a compound annual growth rate (CAGR) basis). Adjusted diluted EPS is a non-GAAP financial measure as it represents diluted EPS from continuing operations attributable to Duke Energy Corporation shareholders, adjusted for the per share impact of special items (as discussed above under Adjusted Diluted EPS). Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items for future periods, such as legal settlements, the impact of regulatory orders or asset impairments.

Adjusted Segment Income and Adjusted Other Net Expense

The materials for Duke Energy's March 2019 Update include a discussion of adjusted segment income and adjusted other net expense for the year-to-date period ended December 31, 2018 and a discussion of 2018 and 2019 forecasted adjusted segment income and forecasted adjusted other net expense.

Adjusted segment income and adjusted other net expense are non-GAAP financial measures, as they represent reported segment income and other net expense adjusted for special items (as discussed above under Adjusted Diluted EPS). Management believes the presentation of adjusted segment income and adjusted other net expense provides useful information to investors, as it provides an additional relevant comparison of a segment's or Other's performance across periods. When an EPS amount is provided for a segment income driver, the per share impact is derived by taking the pretax amount of the item less income taxes based on the consolidated statutory tax rate of 38 percent, except for Duke Energy Renewables, which uses an effective tax rate, divided by the Duke Energy weighted-average diluted shares outstanding for the period. The most directly comparable GAAP measures for adjusted segment income and adjusted other net expense are reported segment income and other net expense, which represents segment income and other net expense from continuing operations, including any special items. A reconciliation of adjusted segment income and adjusted other net expense for the year-to-date period ended December 31, 2018, to the most directly comparable GAAP measures is included herein. Due to the forward-looking nature of any forecasted adjusted segment income and forecasted other net expense and any related growth rates for future periods, information to reconcile these non-GAAP financial measures to the most directly comparable GAAP financial measures are not available at this time, as the company is unable to forecast all special items, as discussed above under Adjusted Diluted EPS Guidance.

Adjusted Effective Tax Rate (ETR)

The materials for Duke Energy's March 2019 Update include a discussion of the adjusted ETR for the year-to-date period ended December 31, 2018. The materials also include a discussion of the 2018 and 2019 forecasted adjusted ETR. Adjusted ETR is a non-GAAP financial measure as the rate is calculated using a pretax earnings and income tax expense, both adjusted for the impact of special items, as discussed above under Adjusted Diluted EPS. The most directly comparable GAAP measure for adjusted ETR is reported effective tax rate. A reconciliation of the adjusted ETR for the year-to-date period ended December 31, 2018 to the most directly comparable GAAP measure is included herein. Due to the forward-looking nature of the 2018 and the 2019 forecasted adjusted ETR, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted Diluted EPS Guidance.

Dividend Payout Ratio

The materials for Duke Energy's March 2019 Update include a discussion of Duke Energy's forecasted dividend payout ratio of 65% - 75% based upon adjusted diluted EPS. This payout ratio is a non-GAAP financial measure as it is based upon forecasted diluted EPS from continuing operations attributable to Duke Energy Corporation shareholders, adjusted for the per-share impact of special items, as discussed above under Adjusted Diluted EPS. The most directly comparable GAAP measure for adjusted diluted EPS is reported diluted EPS from continuing operations attributable to Duke Energy Corporation common shareholders. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted Diluted EPS Guidance.

Adjusted Book Return on Equity (ROE)

The materials for Duke Energy's March 2019 Update include a reference to the historical and projected adjusted book return on equity (ROE) ratio. This ratio is a non-GAAP financial measure. The numerator represents Net Income, adjusted for the impact of special items (as discussed above under Adjusted Diluted EPS). The denominator is average Total Common Stockholder's Equity, reduced for Goodwill. A reconciliation of the components of adjusted ROE to the most directly comparable GAAP measures is included here-in. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted Diluted EPS Guidance.

Funds From Operations ("FFO") Ratios

The materials for Duke Energy's March 2019 Update include a reference to historical and expected FFO to Total Debt ratios. These ratios reflect non-GAAP financial measures. The numerator of the FFO to Total Debt ratio is calculated principally by using net cash provided by operating activities on a GAAP basis, adjusted for changes in working capital, ARO spend, depreciation and amortization of operating leases and reduced for capitalized interest (including any AFUDC interest). The denominator for the FFO to Total Debt ratio is calculated principally by using the balance of long-term debt (excluding purchase accounting adjustments and long-term debt associated with the CR3 Securitization), including current maturities, imputed operating lease liabilities, plus notes payable and commercial paper outstanding. The calculation of FFO to Total Debt ratio for historical periods is included here-in. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted Diluted EPS Guidance.

Holdco Debt Percentage

The materials for Duke Energy's March 2019 Update include a reference to a historical and projected Holdco debt percentage. This percentage reflects a non-GAAP financial measure. The numerator of the Holdco debt percentage is the balance of Duke Energy Corporate debt, Progress Energy, Inc. debt, PremierNotes and the Commercial Paper attributed to the Holding Company. The denominator for the percentage is the balance of long-term debt (excluding purchase accounting adjustments and long-term debt associated with the CR3 Securitization), including current maturities, imputed operating lease liabilities, plus notes payable and commercial paper outstanding.

Available Liquidity

The materials for Duke Energy's March 2019 Update include a discussion of Duke Energy's available liquidity balance. The available liquidity balance presented is a non-GAAP financial measure as it represents Cash and cash equivalents, excluding amounts unavailable for operations, and remaining availability under the master credit and other facilities. The most directly comparable GAAP financial measure for available liquidity is Cash and cash equivalents. A reconciliation of available liquidity as of December 31, 2018 to the most directly comparable GAAP measure is included herein.

Business Mix Percentage

The materials for Duke Energy's March 2019 Update reference each segment's 2019 projected adjusted segment income as a percentage of the total projected 2019 adjusted net income (i.e. business mix), excluding the impact of Other. Duke Energy's segments are comprised of Electric Utilities and Infrastructure, Gas Utilities and Infrastructure and Commercial Renewables.

Adjusted segment income is a non-GAAP financial measure, as it represents reported segment income adjusted for special items as discussed above. Due to the forward-looking nature of any forecasted adjusted segment income, information to reconcile this non-GAAP financial measure to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items (as discussed above under Adjusted Diluted EPS Guidance).

Non-Rider Recoverable O&M

The materials for Duke Energy's March 2019 Update include a discussion of Duke Energy's non-rider recoverable operating, maintenance and other expenses (O&M) for the year-to-date periods ended December 31, 2018, 2017, 2016 and 2015 as well as the forecasted year-to-date period ended December 31, 2019. Non-rider recoverable O&M expenses are non- GAAP financial measures, as they represent reported O&M expenses adjusted for special items and expenses recovered through riders. Management believes that the presentation of non-rider recoverable O&M expenses provides useful information to investors, as it provides a meaningful comparison of financial performance across periods. The most directly comparable GAAP financial measure for non-rider recoverable O&M expenses is reported operating, maintenance and other expenses. A reconciliation of nonrecoverable O&M expenses for the year-to-date periods ended December 31, 2018, 2017, 2016, and 2015, as well as the forecasted year-to-date period ended December 31, 2019, to the most directly comparable GAAP measure are included here-in. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted Diluted EPS Guidance.

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Twelve Months Ended December 31, 2018
(Dollars in millions, except per-share amounts)

		Special Items								
	Reported Earnings	Costs to Achieve Piedmont Merger	Regulatory and Legislative Impacts	Sale of Retired Plant	Impairment Charges	Impacts of the Tax Act	Severance	Discontinued Operations	Total Adjustments	Adjusted Earnings
SEGMENT INCOME										
Electric Utilities and Infrastructure	**$ 3,058**	$ —	$ 202 **B**	$ —	$ 46 **D**	$ 24	$ —	$ —	$ 272	$ 3,330
Gas Utilities and Infrastructure	**274**	—	—	—	42 **E**	1	—	—	43	317
Commercial Renewables	**9**	—	—	—	91 **F**	(3)	—	—	88	97
Total Reportable Segment Income	**3,341**	**—**	**202**	**—**	**179**	**22**	**—**	**—**	**403**	**3,744**
Other	**(694)**	65 **A**	—	82 **C**	—	(2)	144 **H**	—	289	(405)
Discontinued Operations	**19**	—	—	—	—	—	—	(19) **I**	(19)	—
Net Income Attributable to Duke Energy Corporation	**$ 2,666**	**$ 65**	**$ 202**	**$ 82**	**$ 179**	**$ 20 G**	**$ 144**	**$ (19)**	**$ 673**	**$ 3,339**
EPS ATTRIBUTABLE TO DUKE ENERGY CORP, DILUTED	**$ 3.76**	**$ 0.09**	**$ 0.29**	**$ 0.12**	**$ 0.25**	**$ 0.03**	**$ 0.21**	**$ (0.03)**	**$ 0.96**	**$ 4.72**

A - Net of $19 million tax benefit. $84 million recorded within Operating Expenses on the Consolidated Statements of Operations.

B - Net of $16 million tax benefit at Duke Energy Progress and $47 million tax benefit at Duke Energy Carolinas.

- On the Duke Energy Progress Consolidated Statement of Operations, $32 million is recorded within Impairment charges, $31 million within Operations, maintenance and other, $6 million within Interest Expense and $(1) million within Depreciation and amortization.
- On the Duke Energy Carolinas Consolidated Statement of Operations, $188 million is recorded within Impairment charges, $8 million within Operations, maintenance and other, and $1 million within Depreciation and amortization.

C - Net of $25 million tax benefit. $107 million recorded within Gains (Losses) on Sales of Other Assets and Other, net on the Consolidated Statement of Operations.

D - Net of $14 million tax benefit. $60 million recorded within Impairment charges on the Consolidated Statements of Operations

E - Net of $13 million tax benefit. $55 million included within Other Income and Expenses on the Consolidated Statement of Operations.

F - Net of $2 million Noncontrolling Interests. $93 million goodwill impairment recorded within Impairment charges on the Consolidated Statements of Operations.

G - $20 million true up of prior year Tax Act estimates recorded within Income Tax Expense from Continuing Operations on the Consolidated Statements of Operations.

H - Net of $43 million tax benefit. $187 million recorded with Operations, maintenance and other on the Consolidated Statements of Operations.

I - Recorded in Income (Loss) from Discontinued Operations, net of tax on the Consolidated Statements of Operations.

Weighted Average Shares, Diluted (reported and adjusted) - 708 million

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Twelve Months Ended December 31, 2017
(Dollars in millions, except per-share amounts)

		Special Items						
	Reported Earnings	Costs to Achieve Piedmont Merger	Regulatory Settlements	Commercial Renewables Impairments	Impacts of the Tax Act	Discontinued Operations	Total Adjustments	Adjusted Earnings
SEGMENT INCOME								
Electric Utilities and Infrastructure	**$ 3,210**	$ —	$ 98 **B**	$ —	$ (231)	$ —	$ (133)	$ 3,077
Gas Utilities and Infrastructure	**319**	—	—	—	(26) **D**	—	(26)	293
Commercial Renewables	**441**	—	—	74 **C**	(442)	—	(368)	73
Total Reportable Segment Income	**3,970**	**—**	**98**	**74**	**(699)**	**—**	**(527)**	**3,443**
Other	**(905)**	64 **A**	—	—	597	—	661	(244)
Discontinued Operations	**(6)**	—	—	—	—	6 **E**	6	—
Net Income Attributable to Duke Energy Corporation	**$ 3,059**	**$ 64**	**$ 98**	**$ 74**	**$ (102) D**	**$ 6**	**$ 140**	**$ 3,199**
EPS ATTRIBUTABLE TO DUKE ENERGY CORP, DILUTED	**$ 4.36**	**$ 0.09**	**$ 0.14**	**$ 0.11**	**$ (0.14)**	**$ 0.01**	**$ 0.21**	**$ 4.57**

A - Net of $39 million tax benefit. $102 million recorded within Operating Expenses and $1 million recorded within Interest Expense on the Consolidated Statements of Operations.

B - Net of $60 million tax benefit. $154 million recorded within Impairment charges and $4 million recorded within Other Income and Expenses on the Consolidated Statements of Operations.

C - Net of $28 million tax benefit. $92 million recorded within Impairment charges and $10 million recorded within Other Income and Expenses on the Consolidated Statements of Operations.

D - $118 million benefit recorded with Income Tax Expense from Continuing Operations, offset by $16 million expense recorded within Gas Utilities and Infrastructure's Equity in Earnings of Unconsolidated Affiliates on the Consolidated Statements of Operations.

E - Recorded in Income (Loss) from Discontinued Operations, net of tax on the Consolidated Statements of Operations.

Weighted Average Shares, Diluted (reported and adjusted) - 700 million

DUKE ENERGY CORPORATION
ADJUSTED EFFECTIVE TAX RECONCILIATION
December 2018
(Dollars in millions)

	Three Months Ended December 31, 2018		Year Ended December 31, 2018	
	Balance	Effective Tax Rate	Balance	Effective Tax Rate
Reported Income From Continuing Operations Before Income Taxes	$ 433		$ 3,073	
Costs to Achieve Piedmont Merger	31		84	
Regulatory and Legislative Impacts	—		265	
Sale of Retired Plant	—		107	
Impairment Charges	60		206	
Severance	187		187	
Noncontrolling Interests	10		22	
Adjusted Pretax Income	$ 721		$ 3,944	
Reported Income Tax (Benefit) Expense From Continuing Operations	$ (1)	(0.2)%	$ 448	14.6%
Costs to Achieve Piedmont Merger	7		19	
Regulatory and Legislative Impacts	—		63	
Sale of Retired Plant	—		25	
Impairment Charges	14		27	
Severance	43		43	
Impacts of the Tax Act	53		(20)	
Adjusted Tax Expense	$ 116	16.1 % (a)	$ 605	15.3% (a)

	Three Months Ended December 31, 2017		Year Ended December 31, 2017	
	Balance	Effective Tax Rate	Balance	Effective Tax Rate
Reported Income From Continuing Operations Before Income Taxes	$ 866		$ 4,266	
Costs to Achieve Piedmont Merger	34		103	
Regulatory Settlements	23		158	
Commercial Renewables Impairments	18		102	
Impacts of the Tax Act	16		16	
Noncontrolling Interests	—		(5)	
Adjusted Pretax Income	$ 957		$ 4,640	
Reported Income Tax Expense From Continuing Operations	$ 161	18.6%	$ 1,196	28.0%
Costs to Achieve Piedmont Merger	13		39	
Regulatory Settlements	9		60	
Commercial Renewables Impairments	—		28	
Impacts of the Tax Act	118		118	
Adjusted Tax Expense	$ 301	31.5% (a)	$ 1,441	31.1% (a)

(a) Adjusted effective tax rate is a non-GAAP financial measure as the rate is calculated using pretax earnings and income tax expense, both adjusted for the impact of special items. The most directly comparable GAAP measure for adjusted effective tax rate is reported effective tax rate, which includes the impact of special items.

Duke Energy Corporation
Available Liquidity Reconciliation
As of December 31, 2018
(In millions)

Cash and Cash Equivalents	$ 442	
Less: Certain Amounts Held in Foreign Jurisdictions	(7)	
Less: Unavailable Domestic Cash	(67)	
	368	
Plus: Remaining Availability under Master Credit Facilities and other facilities	5,494	
Total Available Liquidity (a)	$ 5,862	approximately 5.9 billion

(a) The available liquidity balance presented is a non-GAAP financial measure as it represents Cash and cash equivalents, excluding certain amounts held in foreign jurisdictions and cash otherwise unavailable for operations, and remaining availability under Duke Energy's available credit facilities, including the master credit facility. The most directly comparable GAAP financial measure for available liquidity is Cash and cash equivalents.

Duke Energy Corporation
Operations, Maintenance and Other Expense
(In millions)

	Actual December 31, 2015	Actual December 31, 2016	Actual December 31, 2017	Actual December 31, 2018	Forecast December 31, 2019
Operation, maintenance and other[(a)]	**$5,539**	**$6,223**	**$5,944**	**$6,463**	**$6,035**
Impact of the Adoption of New Accounting Standards[(b)]	103	–	–	–	–
Adjustments:					
Costs to Achieve, Mergers[(c)]	(69)	(238)	(94)	(83)	–
Severance[(c)]	(142)	(92)	–	(187)	–
Litigation Reserve[(c)]	–	–	–	–	–
Ash Basin Settlement and Penalties[(c)]	(14)	–	–	–	–
Regulatory settlement[(c)]	–	–	(5)	(40)	–
Reagents Recoverable[(d)]	(111)	(93)	(90)	(112)	(100)
Energy Efficiency Recoverable[(d)]	(287)	(417)	(485)	(446)	(433)
Other Deferrals and Recoverable[(d)]	(93)	(233)	(246)	(477)	(452)
Margin based O&M for Commercial Businesses	(48)	(185)	(94)	(113)	(213)
Short-term incentive payments (over)/under budget	(19)	(90)	(22)	(30)	–
Non-Rider Recoverable operation, maintenance and other	**$ 4,859**	**$ 4,875**	**$ 4,908**	**$ 4,974**	**$ 4,837**
YoY change	*3%*	*0%*	*1%*	*1%*	*-3%*

(a) As reported in the Consolidated Statements of Operations.
(b) Beginning January 1, 2018, Duke Energy adopted new accounting guidance for the presentation of net periodic costs related to benefit plans. Prior to this guidance, Duke Energy presented the total non-capitalized net periodic costs within Operation, maintenance and other expense. Retrospective application of this guidance required Duke Energy to reclassify the presentation of non-service cost (benefit) components of net periodic costs to Other income and expenses. In accordance with the transition guidance for the new accounting rules, Operations, maintenance and other expense has been recast for the years ended December 31, 2017 and 2016 and periods prior to January 1, 2016 have not required recasting. This adjustment reflects the historical impact of adopting the new accounting standard to the earliest periods presented (December 31, 2015).
(c) Presented as a special item for the purpose of calculating adjusted earnings and adjusted diluted earnings per share.
(d) Primarily represents expenses to be deferred or recovered through rate riders.

DUKE ENERGY CORPORATION
ADJUSTED BOOK RETURN ON EQUITY (ROEs)
For the period ended December 31, 2018
dollars in millions

	Duke Energy Carolinas	Duke Energy Progress	Total Carolinas	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio Reportable Segments	Piedmont
Reported Net Income 2018	$ 1,071	$ 667	$ 1,738	$ 553	$ 393	$ 279 (2)	$ 124 (4)
Special Items (1)	234	118	352	63	8	-	40
Adjusted Net Income 2018	1,305	785	2,090	616	401	279	164
2018							
Equity	11,683	8,441	20,124	6,095	4,339	3,449 (3)	2,047 (5)
Goodwill	-	-	-	-	-	920	49
Equity less Goodwill	11,683	8,441	20,124	6,095	4,339	2,529	1,998
2017							
Equity	11,361	7,949	19,310	5,618	4,121	3,166 (3)	1,616 (5)
Goodwill	-	-	-	-	-	920	49
Equity less Goodwill	11,361	7,949	19,310	5,618	4,121	2,246	1,567
Average Equity less Goodwill			19,717	5,857	4,230	2,388	1,783
Adjusted Book ROEs			10.6%	10.5%	9.5%	11.7%	9.2%

(1) Costs to Achieve (CTA) Mergers net of tax, Severance, Regulatory and Legislative Impacts and Tax Reform.

(2) Net Income for 2018 equals Duke Energy Ohio reportable segments segment income, which already excludes CTA and cost savings initiatives, Severance and Sale of Retired Plant.

(3) Reconciliation of Duke Energy Ohio Equity to Equity of the reportable segments:

	2018	2017
Reported Equity for Duke Energy Ohio	3,445	3,163
Less: Non-Reg & Other	(4)	(3)
Duke Energy Ohio Reportable Segments Equity	3,449	3,166

(4) Piedmont Natural Gas Net Income excludes $5 million of income related to Investments in Gas Transmission Infrastructure.

(5) Reconciliation of Piedmont Natural Gas Equity to reported equity:

	2018	2017
Reported Equity for Piedmont Natural Gas	2,091	1,662
Less: Investments in Gas Transmission Infrastructure	44	46
Piedmont Natural Gas Adjusted Equity	2,047	1,616

DUKE ENERGY CORPORATION
ADJUSTED BOOK RETURN ON EQUITY (ROEs)
For the period ended December 31, 2017
dollars in millions

	Duke Energy Carolinas	Duke Energy Progress	Total Carolinas	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio Reportable Segments		Piedmont	
Reported Net Income 2017	$ 1,214	$ 715	$ 1,929	$ 712	$ 354	$ 223	(2)	$ 133	(4)
Special Items (1)	28	(17)	11	(136)	58	(20)		25	
Adjusted Net Income 2017	1,242	698	1,940	576	412	203		158	
2017									
Equity	11,361	7,949	19,310	5,618	4,121	3,166	(3)	1,616	(5)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	11,361	7,949	19,310	5,618	4,121	2,246		1,567	
2016									
Equity	10,772	7,358	18,130	4,900	4,067	3,027	(3)	1,569	(5)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	10,772	7,358	18,130	4,900	4,067	2,107		1,520	
Average Equity less Goodwill			18,720	5,259	4,094	2,177		1,544	
Adjusted Book ROEs			10.4%	11.0%	10.1%	9.3%		10.2%	

(1) Costs to Achieve (CTA), Mergers net of tax, Regulatory Settlements, and Tax Reform.

(2) Net Income for 2017 equals Duke Energy Ohio reportable segments segment income, which already excludes CTA and cost savings initiatives.

(3) Reconciliation of Duke Energy Ohio Equity to Equity of the reportable segments:

	2017	2016
Reported Equity for Duke Energy Ohio	3,163	2,996
Less: Non-Reg & Other	(3)	(31)
Duke Energy Ohio Reportable Segments Equity	3,166	3,027

(4) Piedmont Natural Gas Net Income excludes $6 million of income related to Investments in Gas Transmission Infrastructure.

(5) Reconciliation of Piedmont Natural Gas Equity to reported equity:

	2017	2016
Reported Equity for Piedmont Natural Gas	1,662	1,672
Less: Investments in Gas Transmission Infrastructure	46	103
Piedmont Natural Gas Adjusted Equity	1,616	1,569

DUKE ENERGY CORPORATION
ADJUSTED BOOK RETURN ON EQUITY (ROEs)
For the period ended December 31, 2016
dollars in millions

	Duke Energy Carolinas	Duke Energy Progress	Total Carolinas	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio Reportable Segments		Piedmont Natural Gas (4)	
Reported Net Income 2016	$ 1,166	$ 599	$ 1,765	$ 551	$ 381	$ 231	(2)	$ 187	(5)
Special Items (1)	91	50	141	19	10	-		(40)	(6)
Adjusted Net Income 2016	1,257	649	1,906	570	391	231		147	
2016									
Equity	10,772	7,358	18,130	4,900	4,067	3,027	(3)	1,487	(7)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	10,772	7,358	18,130	4,900	4,067	2,107		1,438	
2015									
Equity	11,606	7,059	18,665	5,121	3,836	2,855	(3)	1,299	(7)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	11,606	7,059	18,665	5,121	3,836	1,935		1,250	
Average Equity less Goodwill			18,398	5,011	3,952	2,021		1,344	
Adjusted Book ROEs			10.4%	11.4%	9.9%	11.4%		10.9%	

(1) Costs to Achieve (CTA), Mergers net of tax and Cost Savings Initiatives.

(2) Net Income for 2016 equals Duke Energy Ohio reportable segments segment income, which already excludes CTA and cost savings initiatives.

(3) Reconciliation of Duke Energy Ohio Equity to Equity of the reportable segments:

	2016	2015
Reported Equity for Duke Energy Ohio	2,996	2,784
Less: Non-Reg & Other	(31)	(71)
Duke Energy Ohio Reportable Segments	3,027	2,855

(4) Piedmont Natural Gas ROE is for the twelve months ended October 31, 2016.

(5) Piedmont Natural Gas Net Income excludes $6 million of income related to Investments in Gas Transmission Infrastructure.

(6) Piedmont special items include:

Gain on sale of SouthStar equity method investment, net of tax	(81)
CTA	41
	(40)

(7) Reconciliation of Piedmont Natural Gas Equity to reported equity:

	October 31, 2016	October 31, 2015
Reported Equity for Piedmont Natural Gas	1,645	1,426
Less: Investments in Gas Transmission Infrastructure	158	127
Piedmont Natural Gas Adjusted Equity	1,487	1,299

Duke Energy Corporation
2019 Forecasted Cash Flow Reconciliation, Required by SEC Regulation G
February 14, 2019
($ in millions)

		Forecast 2019
Primary Sources:		
Adjusted net income (1)	(a)	$3,645
Depreciation & amortization	(a)	4,970
Deferred and accrued taxes	(a)	1,260
Other sources / (uses), net	(a)	(340)
Total Sources		9,535
Primary Uses:		
Capital expenditures (including discretionary)	(b)	(11,100)
Dividends	(c)	(2,750)
Total Uses		(13,850)
Uses in Excess of Sources		(4,315)
Net Change in Financing		
Debt issuances	(c)	7,485
Debt maturities	(c)	(3,890)
Net Change in Debt		3,595
Common stock issuances	(c)	500
Net Change in Cash		($220)
Reconciliations to forecasted U.S. GAAP reporting amounts:		
Operating cash flow components, sum of (a) from above		$9,535
Reconciling items to GAAP cash flows from operating activities	(2)	(1,525)
Net cash provided by operating activities per GAAP Consolidated Statement of Cash Flows		$8,010
Investing cash flow components, (b) from above		($11,100)
Reconciling items to GAAP cash flows from investing activities	(2)	910
Net cash used in investing activities per GAAP Consolidated Statement of Cash Flows		($10,190)
Financing cash flow components, sum of (c) from above		$1,345
Reconciling items to GAAP cash flows from financing activities	(2)	615
Net cash used in financing activities per GAAP Consolidated Statement of Cash Flows		$1,960
Debt maturities [(d) from above] includes "Notes payable and commercial paper" which is separately presented per GAAP Consolidated Statements of Cash Flows		
Net decrease in cash and cash equivalents per forecasted GAAP Consolidated Statements of Cash Flows		($220)

Notes:

(1) The forecasted adjusted net income of $3,645 million for 2019 is an illustrative amount based on the midpoint of Duke Energy's adjusted diluted EPS outlook range of $4.80-$5.20 per share. The EPS measure used for employee incentive compensation is primarily based on adjusted diluted EPS. Adjusted diluted EPS is a non-GAAP financial measure as it represents diluted EPS from continuing operations attributable to Duke Energy Corporation shareholders and adjusted for the per-share impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis, although it is reasonably possible such charges and credits could recur. The most directly comparable GAAP measure for adjusted diluted EPS is reported diluted EPS from continuing operations attributable to Duke Energy Corporation common shareholders, which includes the impact of special items. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items.

(2) Amount consists primarily of an adjustment for operating cashflow items (principally payments for asset retirement obligations) included in the "Capital expenditures (including discretionary)", which are combined for the GAAP reconciliation in Investing activities; an adjustment for investing cash flow items (principally proceeds from sales and maturities of available-for-sale securities and Other) included in the "Other sources/(uses), net", which are combined for the GAAP reconciliation in Operating activities, and ; an adjustment for financing cash flow items (principally proceeds from Noncontrolling Interests initial investments and payments for interest on preferred debt/equity content securities) included in the "Other sources/(uses), net" and "Capital expenditures (including discretionary)', which are combined for the GAAP reconciliation in Operating activities and Investing activities.

FFO to Debt Calculation
Duke Energy Corporation
(in millions)

	Years Ended December 31, 2018 Actual	Years Ended December 31, 2017 Actual
Cash From Operations	$ 7,186	$ 6,624
Working capital adjustment (1)	138	752
ARO spend	533	571
Capitalized Interest	(161)	(128)
CR3 securitization adjustment	(52)	(53)
Lease imputed adjustments	196	176
Other	6	4
Funds From Operations	**7,846**	**7,946**
Notes payable and commercial paper	$ 3,410	$ 2,163
Current maturities of long-term debt	3,406	3,244
Long-term debt	51,123	49,035
Purchase accounting adjustments	(2,171)	(2,416)
CR3 securitization	(1,164)	(1,217)
ACP construction loan	677	317
Hybrid debt adjustment	(250)	(125)
Lease imputed debt (2)	1,608	1,446
Total Debt	**$ 56,639**	**$ 52,447**
FFO / Debt	**14%**	**15%**

(1) Working capital detail, excluding mark-to-market

	2018	2017
Receivables	$ (345)	$ (83)
Inventory	156	268
Other current assets	(721)	(400)
Accounts payable	479	(204)
Taxes accrued	23	149
Other current liabilities	270	(482)
	$ (138)	$ (752)

(2) Lease imputed debt for Duke Energy Corporation is calculated as six times annual rent expense for the period ended December 31, 2018.

FFO to Debt Calculation
Duke Energy Carolinas
(in millions)

	Years Ended December 31, 2018 Actual	2017 Actual
Cash From Operations	$ 2,530	$ 2,634
Working capital adjustment (1)	96	(54)
ARO spend	230	271
Capitalized Interest	(35)	(45)
Lease imputed adjustments	40	36
Funds From Operations	**2,861**	**2,842**
Current maturities of long-term debt	$ 6	$ 1,205
Long-term debt	10,633	8,598
Long-term debt payable to affiliated companies	300	300
Notes payable to affiliated companies	439	104
Lease imputed debt (2)	196	176
Total Debt	**$ 11,574**	**$ 10,383**
FFO / Debt	**25%**	**27%**
(1) Working capital detail, excluding mark-to-market		
Receivables	$ (86)	$ (9)
Receivables from affiliated companies	(87)	68
Inventory	25	78
Other current assets	(161)	7
Accounts payable	168	23
Accounts payable to affiliated companies	21	(38)
Taxes accrued	(65)	86
Other current liabilities	89	(161)
	$ (96)	$ 54

(2) Lease imputed debt for Duke Energy Carolinas is calculated as four times annual rent expense for the period ended December 31, 2018.

FFO to Debt Calculation
Duke Energy Progress
(in millions)

	Years Ended December 31, 2018 Actual	2017 Actual
Cash From Operations	$ 1,628	$ 1,195
Working capital adjustment (1)	(88)	520
ARO spend	195	192
Capitalized Interest	(26)	(21)
Lease imputed adjustments	62	62
Funds From Operations	**1,771**	**1,948**
Notes payable to affiliated companies	$ 294	$ 240
Current maturities of long-term debt	603	3
Long-term debt	7,451	7,204
Long-term debt payable to affiliated companies	150	150
Lease imputed debt (2)	300	300
Total Debt	**$ 8,798**	**$ 7,897**
FFO / Debt	**20%**	**25%**
(1) Working capital detail, excluding mark-to-market		
Receivables	$ (107)	$ (58)
Receivables from affiliated companies	(20)	2
Inventory	63	59
Other current assets	(201)	(75)
Accounts payable	219	(230)
Accounts payable to affiliated companies	99	(48)
Taxes accrued	(11)	(39)
Other current liabilities	46	(131)
	$ 88	$ (520)

(2) Lease imputed debt for Duke Energy Progress is calculated as four times annual rent expense for the period ended December 31, 2018.

FFO to Debt Calculation
Duke Energy Florida
(in millions)

	Years Ended December 31, 2018 Actual	2017 Actual
Cash From Operations	$ 1,109	$ 1,015
Working capital adjustment (1)	(129)	229
ARO spend	35	56
Capitalized Interest	(25)	(24)
CR3 securitization adjustment	(52)	(53)
Lease imputed adjustments	56	45
Funds From Operations	**994**	**1,268**
Notes payable to affiliated companies	$ 108	$ -
Current maturities of long-term debt	270	768
Long-term debt	7,051	6,327
CR3 securitization	(1,164)	(1,217)
Lease imputed debt (2)	272	220
Total Debt	**$ 6,537**	**$ 6,098**
FFO / Debt	**15%**	**21%**

(1) Working capital detail, excluding mark-to-market		
Receivables	$ (100)	$ (38)
Receivables from affiliated companies	(26)	-
Inventory	58	66
Other current assets	59	(138)
Accounts payable	(1)	(32)
Accounts payable to affiliated companies	17	(51)
Taxes accrued	40	1
Other current liabilities	82	(37)
	$ 129	$ (229)

(2) Lease imputed debt for Duke Energy Florida is calculated as four times annual rent expense for the period ended December 31, 2018.

FFO to Debt Calculation
Duke Energy Indiana
(in millions)

	Years Ended December 31, 2018 Actual	2017 Actual
Cash From Operations	$ 1,006	$ 969
Working capital adjustment (1)	(17)	(102)
ARO spend	69	45
Capitalized Interest	(27)	(9)
Lease imputed adjustments	17	19
Funds From Operations	**1,048**	**922**
Notes payable to affiliated companies	$ 167	$ 161
Current maturities of long-term debt	63	3
Long-term debt	3,569	3,630
Long-term debt payable to affiliated companies	150	150
CRC allocated balance	174	174
Lease imputed debt (2)	84	92
Total Debt	**$ 4,207**	**$ 4,210**
FFO / Debt	**25%**	**22%**
(1) Working capital detail, excluding mark-to-market		
Receivables	$ 7	$ 59
Receivables from affiliated companies	3	(11)
Inventory	28	54
Other current assets	(25)	28
Accounts payable	37	(86)
Accounts payable to affiliated companies	5	4
Taxes accrued	(52)	64
Other current liabilities	14	(10)
	$ 17	$ 102

(2) Lease imputed debt for Duke Energy Indiana is calculated as four times annual rent expense for the period ended December 31, 2018.

FFO to Debt Calculation
Duke Energy Ohio
(in millions)

	Years Ended December 31, 2018 Actual		Years Ended December 31, 2017 Actual	
Cash From Operations	$	570	$	479
Working capital adjustment (1)		(32)		15
ARO spend		3		7
Capitalized Interest		(17)		(10)
Lease imputed adjustments		11		12
Funds From Operations		**535**		**503**
Notes payable to affiliated companies	$	274	$	29
Current maturities of long-term debt		551		3
Long-term debt		1,589		2,039
Long-term debt payable to affiliated companies		25		25
CRC allocated balance		151		151
Lease imputed debt (2)		52		60
Total Debt	**$**	**2,642**	**$**	**2,307**
FFO / Debt		**20%**		**22%**

(1) Working capital detail, excluding mark-to-market				
Receivables	$	(33)	$	2
Receivables from affiliated companies		19		(4)
Inventory		7		6
Other current assets		16		(22)
Accounts payable		(19)		12
Accounts payable to affiliated companies		16		(1)
Taxes accrued		12		11
Other current liabilities		14		(19)
	$	32	$	(15)

(2) Lease imputed debt for Duke Energy Ohio is calculated as four times annual rent expense for the period ended December 31, 2018.

FFO to Debt Calculation
Piedmont Natural Gas
(in millions)

	Years Ended December 31, 2018 Actual	2017 Actual
Cash From Operations	$ 478	$ 349
Working capital adjustment (1)	(185)	125
Capitalized Interest	17	12
Lease imputed adjustments	9	6
Funds From Operations	**319**	**492**
Notes payable	$ 198	$ 364
Current maturities of long-term debt	350	250
Long-term debt	1,788	1,787
Lease imputed debt (2)	44	28
Total Debt	**$ 2,380**	**$ 2,429**
FFO / Debt	**13%**	**20%**

(1) Working capital detail, excluding mark-to-market		
Receivables	$ 7	$ (40)
Receivables from affiliated companies	(15)	-
Inventory	(4)	-
Other current assets	71	(20)
Accounts payable	15	(13)
Accounts payable to affiliated companies	25	5
Taxes accrued	65	(48)
Other current liabilities	21	(9)
	$ 185	$ (125)

(2) Lease imputed debt for Piedmont Natural Gas is calculated as four times annual rent expense for the period ended December 31, 2018.

DUKE ENERGY®

Earnings Review & Business Update

FOURTH QUARTER 2019

Lynn Good *Chairman / President and CEO*
Steve Young *Executive Vice President and CFO*

February 13, 2020

Safe Harbor statement

This presentation includes forward-looking statements within the meaning of the federal securities laws. Actual results could differ materially from such forward-looking statements. The factors that could cause actual results to differ are discussed in the Appendix herein and in Duke Energy's SEC filings, available at www.sec.gov.

Regulation G disclosure

In addition, today's discussion includes certain non-GAAP financial measures as defined under SEC Regulation G. A reconciliation of those measures to the most directly comparable GAAP measures is available in the Appendix herein and on our Investor Relations website at www.duke-energy.com/investors/.

Delivering on commitments

DELIVERING ON FINANCIAL RESULTS...

- ✓ 2019 EPS above guidance range midpoint
- ✓ Strong year-over-year results represent 7% growth
- ✓ Well positioned to continue to deliver 4-6% EPS growth

AND COMMITMENT TO THE DIVIDEND...

- ✓ 93rd consecutive year paying a dividend

...WHILE MAINTAINING FOCUS ON THE CUSTOMER

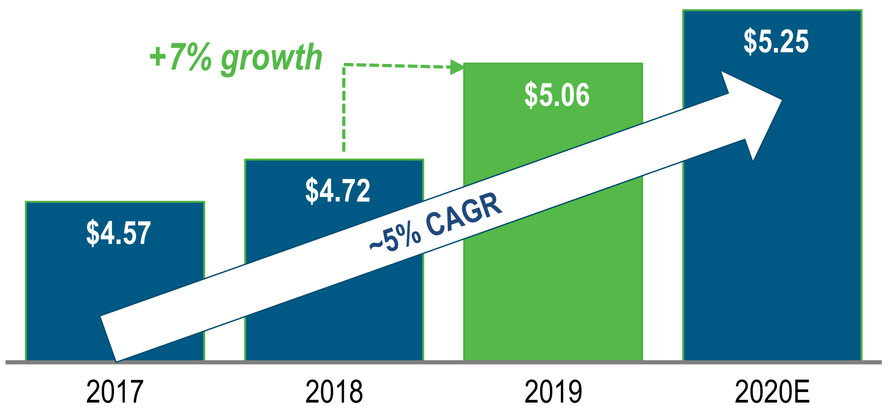
- ✓ Delivered outstanding improvement in customer service, increasing reliability measures by 15% and customer satisfaction measures by 25%

$5.06 IN 2019

2019 REPORTED AND ADJUSTED EPS

IN TOP HALF OF GUIDANCE RANGE

ADJUSTED EPS GROWTH



$5.25 TARGET MIDPOINT FOR 2020

INTRODUCING 2020 ADJUSTED EPS

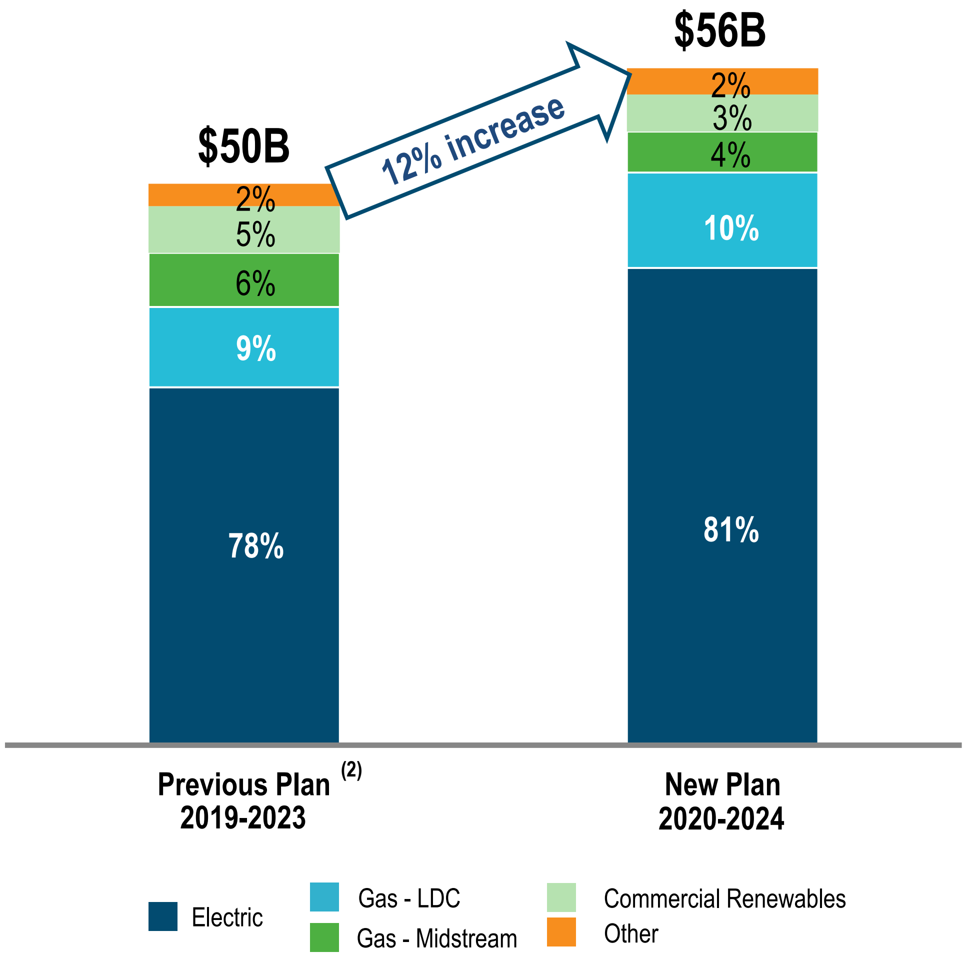
GUIDANCE RANGE OF $5.05-$5.45

4% – 6% GROWTH THROUGH 2024 OFF MIDPOINT OF ORIGINAL 2019 ADJUSTED EPS GUIDANCE RANGE ($5.00)

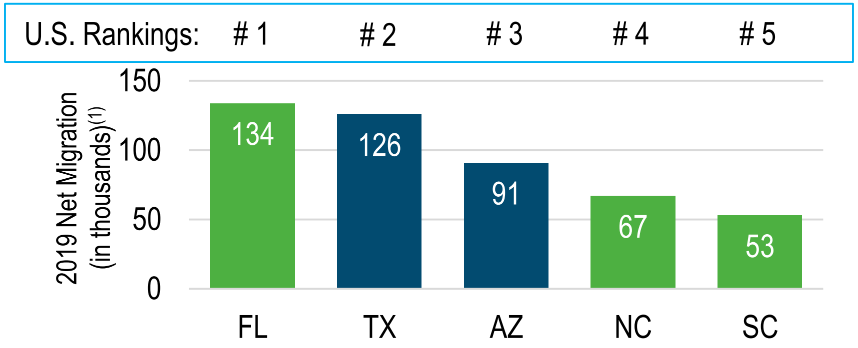
Rapidly expanding infrastructure needs driven by strong fundamental growth

DUKE ENERGY.

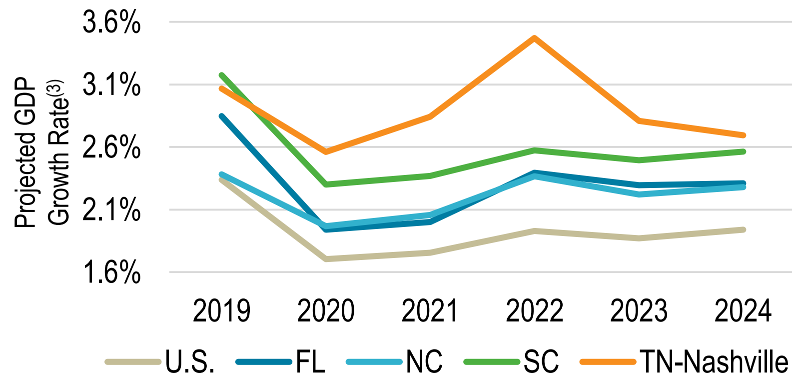
12% INCREASE IN 5-YEAR CAPITAL PLAN; LOW RISK INVESTMENTS



SERVING THREE OF THE MOST VIBRANT STATES IN THE COUNTRY



GDP GROWTH PROJECTIONS ABOVE THE NATIONAL AVERAGE



(1) Source: Wells Fargo Securities; U.S. Department of Commerce
(2) As disclosed in the Fourth Quarter 2018 Earnings Review and Business Update on Feb. 14, 2019
(3) Source: U.S. Bureau of Economic Analysis (BEA); Moody's Analytics Forecasted

VITALITY OF COMMUNITIES DRIVES REGULATED FOCUSED GROWTH

Our purpose, vision and commitment to stakeholder engagement

Newport Tie Station; York, SC

DUKE ENERGY'S GUIDING PRINCIPLES

Our purpose:

Power the lives of our customers and the vitality of our communities

Our vision:

Lead the way to cleaner, smarter energy solutions that customers value

2019 STAKEHOLDER ENGAGEMENT RESULTS

- ✓ Reached landmark settlement with NCDEQ and community groups to finalize closure plans for low risk coal ash sites
- ✓ North Carolina storm securitization legislation passed
- ✓ Achieved constructive outcomes in Piedmont rate cases
- ✓ Announced new goal of net zero CO_2 emissions by 2050

ESG is an essential component of Duke Energy's strategy

DUKE ENERGY

ENVIRONMENTAL

- Industry-leading climate goal of net-zero carbon emissions by 2050
- Announced over 1,500 MW of new wind and solar projects in 2019
- Further reduced CO_2 emissions by an additional 8% in 2019 from 2005 levels, bringing total decrease to 39%(1)
- Named to Dow Jones Sustainability North America Index for 14 years in a row
- Clear leader in energy efficiency savings in Southeast

SOCIAL RESPONSIBILITY

- One of the industry leaders for 5th year in a row in safety
- Named one of "America's Best Employers" by Forbes in 2019 and one of Fortune's "Worlds Most Admired Companies" for 3rd consecutive year
- Earned perfect score for third year in a row on the Human Rights Campaign Corporate Equality Index; also awarded "Best Places to Work for LGBTQ Equality"

GOVERNANCE & TRANSPARENCY

- Bloomberg ESG disclosure score of 57.4, the third best score and in the top quartile of U.S. utilities
- Climate report utilizes TCFD(2) framework; our pathway is consistent with 2-degree scenario
- 2019 board refreshment enhanced diversity (40% racial, gender and ethnic diversity)
- Strong ESG ratings from ISS Quality Score in 2019

ANNOUNCING DUKE ENERGY'S ESG INVESTOR DAY IN MAY 2020 – DETAILS TO FOLLOW

(1) *Year to year reductions will be influenced by customer demand for electricity, weather, fuel and purchased power prices, and other factors*
(2) *TCFD – Task Force on Climate-related Financial Disclosures*

Significant investment needs in our communities through 2030 and beyond

DUKE ENERGY.

MODERNIZE THE ENERGY GRID

- Improving the largest grid in the United States to support:
  - Carbon reduction goals / renewables penetration
  - Hardening and resiliency against storms / grid security
  - Population and economic growth of our vibrant communities

GENERATE CLEANER ENERGY

- Targeting ≥ 50% reduction in CO_2 emissions by 2030[(1)] and net zero by 2050
- Transitioning from coal to renewables and natural gas in the Carolinas and Midwest
- Meeting solar demands of our Florida customers with >1,750 MW to be built 2019-2030

EXPAND NATURAL GAS INFRASTRUCTURE

- Focusing on gas infrastructure needs in the Southeast to support:
  - Robust customer growth
  - Integrity management programs
  - Cleaner electric power generation transformation
- Midstream investments currently limited to the Atlantic Coast Pipeline

SIGNIFICANT INVESTMENT RUNWAY BEYOND THE 5 YEAR PLAN REPRESENTS UNIQUE, LONG-TERM SHAREHOLDER VALUE PROPOSITION

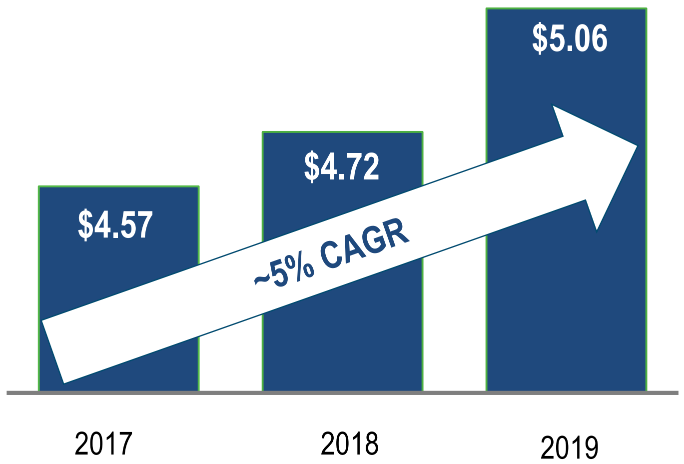
(1) From 2005 levels

2019 Financial results

$5.06

2019 REPORTED AND ADJUSTED EPS
ABOVE MIDPOINT OF
ORIGINAL AND REVISED GUIDANCE RANGE(1)

ADJUSTED EARNINGS PER SHARE



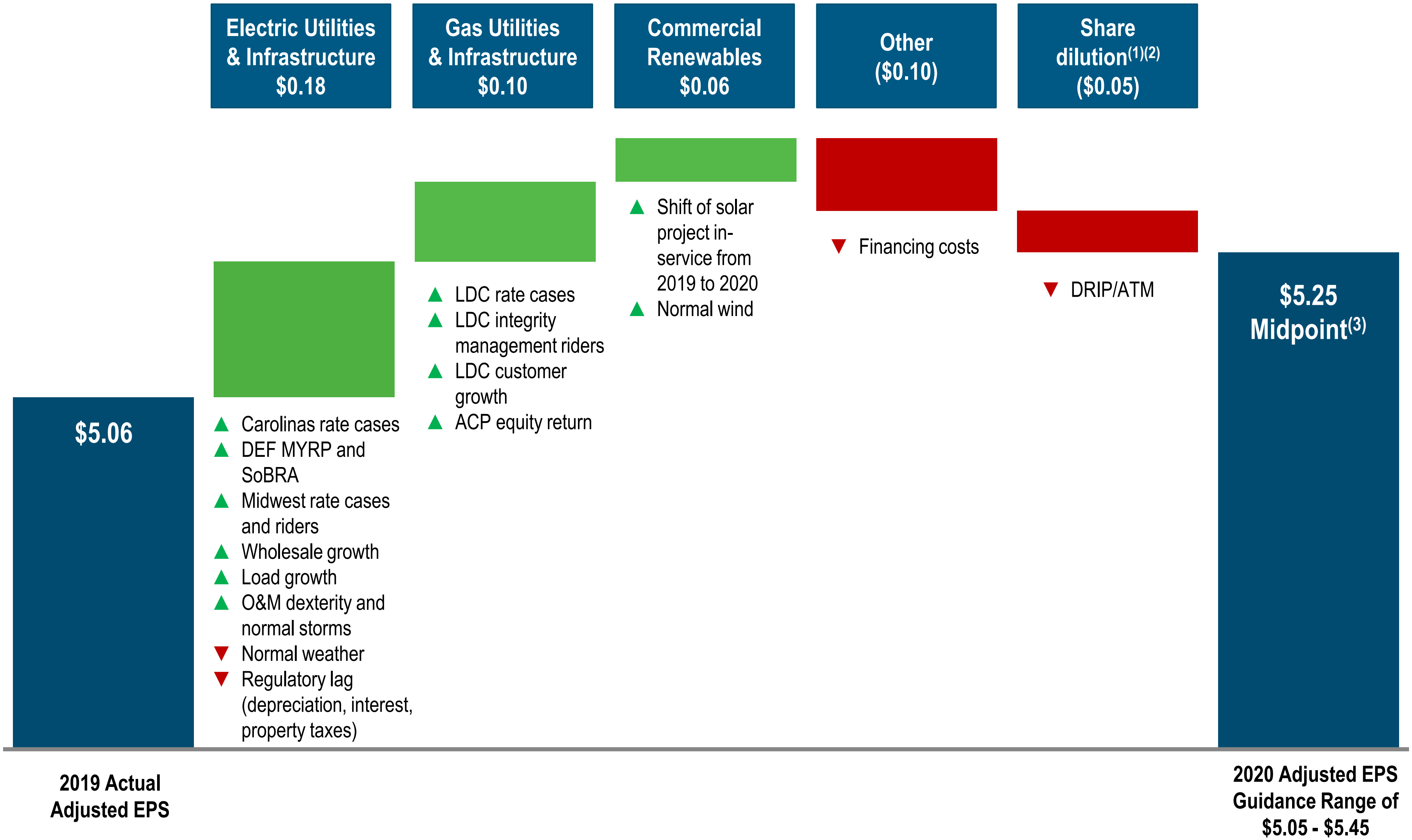
2019 KEY MESSAGES

- Delivered ~5% adjusted EPS CAGR from 2017 (first year of portfolio transition) through 2019
- Achieved solid year-over-year growth in each operating segment:
  - Electric Utilities and Infrastructure, +$0.25 per share
  - Gas Utilities and Infrastructure, +$0.18 per share
  - Commercial renewables, +$0.13 per share
  - Other, -$0.08 per share
  - Share dilution, -$0.14 per share
- Demonstrated dexterity in response to favorable 2019 total volumes, for example:
  - Deployed strategic O&M spend on behalf of customers and communities ($0.06) per share
  - Absorbed Hurricane Dorian costs ($0.04) per share

2019 RESULTS AND AGILITY POSITION THE COMPANY WELL TO DELIVER ON 2020 AND 2021 FINANCIAL TARGETS

(1) *Based on adjusted EPS and the original 2019 midpoint of $5.00 and revised guidance midpoint of $5.05*

2020 Financial outlook – adjusted EPS waterfall



(1) *Minimal dilution from $2.5 billion equity forward as settlement expected in December 2020*
(2) *Based on weighted average basic shares which exclude dilution imputed for GAAP purposes during the period between pricing (Nov. 2018) and settlement (Dec. 2020) of the $2.5 billion equity forward*
(3) *Midpoint of 2020 adjusted EPS guidance range of $5.05 - $5.45*

2021 Primary EPS growth drivers

Electric Utilities & Infrastructure

- ⬆ Florida multi-year rate plan and Solar BRA
- ⬆ Rate case full year impact:
  - Indiana and Kentucky
  - DEC/DEP NC
- ⬆ Midwest grid investments (DEI/DEO)
- ⬆ Load growth consistent with 0.5% long-term expectation
- ⬌ Cost management through digital capabilities and other efficiencies keeps O&M relatively flat

Gas Utilities & Infrastructure

- ⬆ Atlantic Coast Pipeline
- ⬆ Customer growth, integrity management investments, power generation gas infrastructure

Other Drivers

- ⬇ Share dilution:
  - Dilution in 2021 from $2.5 billion equity forward fully offset by incremental AFUDC earnings on ACP
  - $500 million of DRIP/ATM

REAFFIRMING 4% - 6% EPS GROWTH THROUGH 2024(1)

(1) *Based on adjusted EPS and the original 2019 guidance midpoint of $5.00*

$6B Increase in capital plan drives significant earnings base growth

Florida - $1.5B increase

- Grid hardening supported by Storm Protection Plan regulations (SB 796)
- Solar investments
- Underpinned by highest net migration in the U.S.[1]

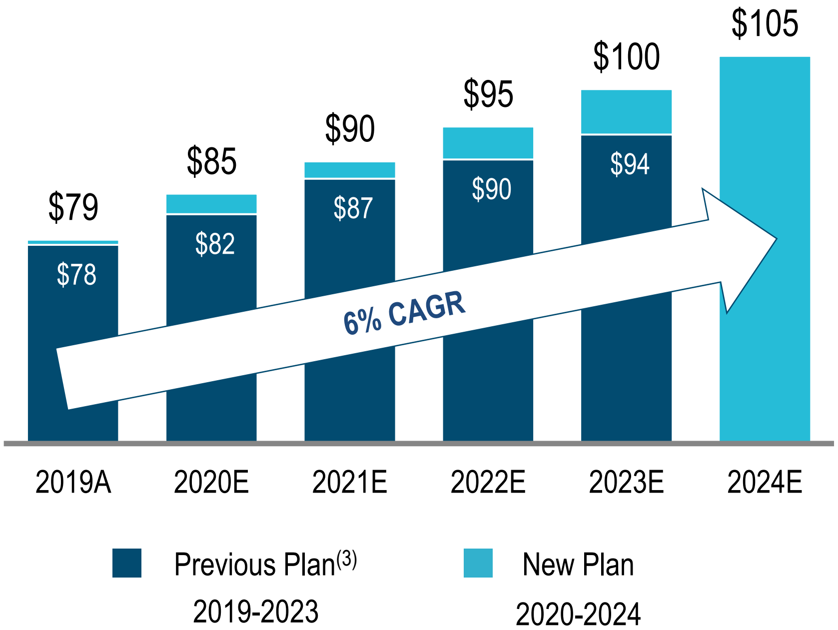
Carolinas - $4B increase

- T&D grid of DEC and DEP represents one of the largest systems in the country
- T&D investment needs driven by migration that ranks 4th (NC) and 5th (SC) in the U.S.[1] and NC solar penetration that ranks 2nd in the U.S.
- Storm hardening and resiliency

Gas LDCs - $1B increase

- Integrity management programs
- Infrastructure to support strong customer growth

REGULATED ELECTRIC AND GAS EARNINGS BASE[2]



(1) Source: Wells Fargo Securities; U.S. Department of Commerce
(2) In billions. Illustrative earnings base for presentation purposes only and includes retail and wholesale; Amounts as of the end of each year shown; Projected earnings base = prior period earnings base + capex - D&A - deferred taxes
(3) As disclosed in the Fourth Quarter 2018 Earnings Review and Business Update on Feb. 14, 2019

STRENGTHENED BALANCE SHEET (BBB+/BAA1 STABLE) UNDERPINS ABILITY TO EXECUTE ON $56B CAPITAL PLAN

Balance sheet strength and equity financing plan

DUKE ENERGY.

KEY MESSAGES

- Committed to maintaining strong credit quality, including investment-grade ratings
  - Credit ratings recently affirmed at BBB+/Baa1 (Stable)
  - Credit metrics are consistently solid over the planning horizon
- Settlement of ~$2.5 billion equity forward to occur in Dec. 2020
- Expected equity issuances of $500 million per year 2020-2022 via DRIP/ATM programs; will evaluate continuing need for DRIP/ATM programs upon in-service of ACP

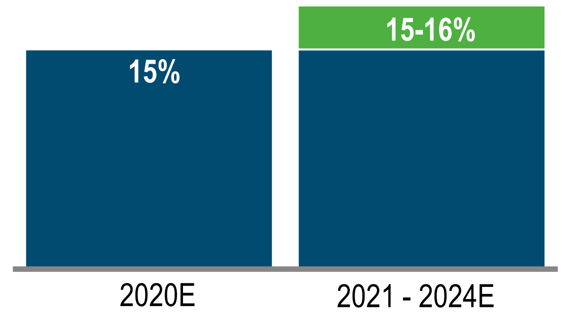
UNIQUE FACTORS CONTRIBUTING TO BALANCE SHEET STRENGTH

- ~$275 million refundable AMT credits expected in 2020
- Not expected to be a significant taxpayer until 2027 timeframe
- Pension plan 107% funded – no contributions forecasted in five-year plan

PRIMARY CREDIT METRICS

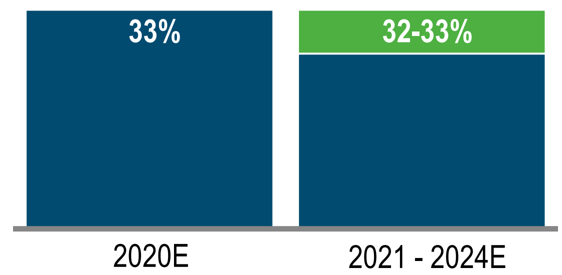
FFO/DEBT

Target: 15 - 16%



HOLDCO DEBT %

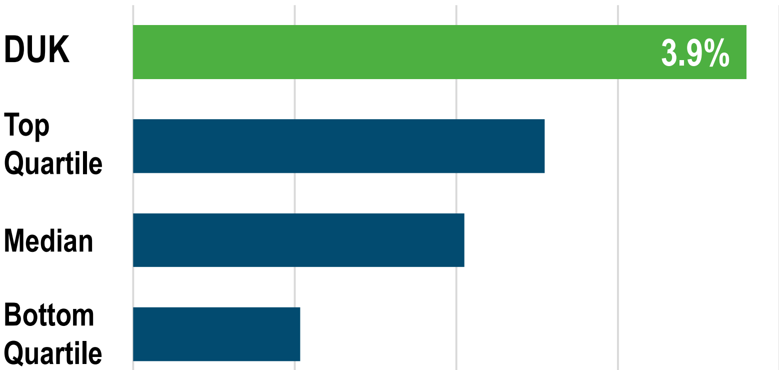
Target: Low 30%'s



EQUITY ISSUANCE PLAN REMAINS UNCHANGED FROM 3Q 2019 EARNINGS CALL

Ongoing commitment to the dividend

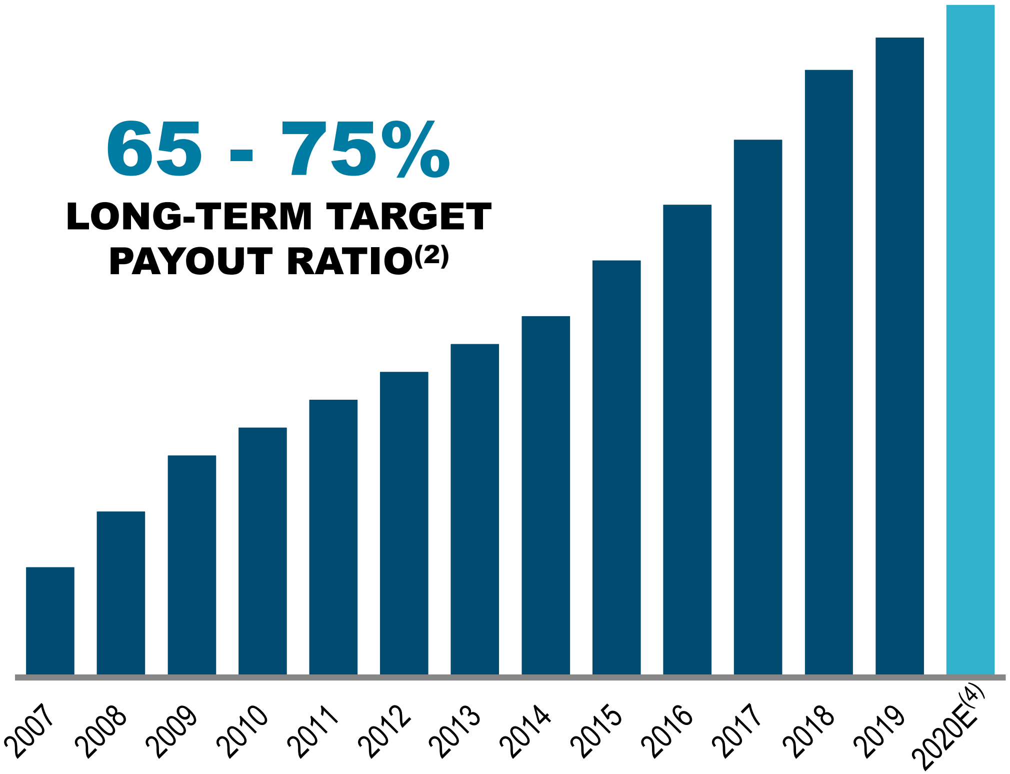
TOP TIER DIVIDEND YIELD[1] PROVIDES LOW RISK RETURNS…



…WITH A PROVEN TRACK RECORD OF DIVIDEND GROWTH[3][4]

65 - 75%

LONG-TERM TARGET PAYOUT RATIO[2]



(1) As of Feb. 11, 2020. Compared to UTY constituents
(2) Based on adjusted EPS
(3) Reflects annualized Q4 dividend per share for each year
(4) Subject to approval by the Board of Directors

Focused on investor value creation

DUK LISTED NYSE

A STRONG LONG-TERM RETURN PROPOSITION

DUK LISTED NYSE

3.9%

DIVIDEND YIELD[(1)] WITH DIVIDEND **GROWTH COMMITMENT**[(2)]

~8-10%

ATTRACTIVE RISK-ADJUSTED **TOTAL SHAREHOLDER RETURN**[(3)]

4-6%

HIGHLY ACHIEVABLE **EPS GROWTH THROUGH 2024**[(4)]

CONSTRUCTIVE JURISDICTIONS, LOW-RISK REGULATED INVESTMENTS AND BALANCE SHEET STRENGTH

(1) *As of Feb. 11, 2020*
(2) *Subject to approval by the Board of Directors.*
(3) *Total shareholder return proposition at a constant P/E ratio*
(4) *Based on adjusted EPS off the midpoint of the 2019 guidance range ($5.00)*

Appendix

Advancing our strategic vision

TRANSFORM THE
CUSTOMER EXPERIENCE

MODERNIZE THE
ENERGY GRID

GENERATE
CLEANER ENERGY

EXPAND **NATURAL GAS**
INFRASTRUCTURE

STAKEHOLDER
ENGAGEMENT

EMPLOYEE ENGAGEMENT AND OPERATIONAL EXCELLENCE ARE FOUNDATIONAL TO OUR SUCCESS

Atlantic Coast Pipeline – project update

FINANCIAL CONSIDERATIONS

- Expect mechanical completion of the project in late 2021 with full in-service in the first half of 2022
- Estimated cost of approximately $8.0 billion(1)
  - ACP represents ~ 4% of Duke Energy's 5-year capital plan
- Expected EPS contribution from the project(2):
  - 2020: ~$0.20 cents per share
  - Full-year in-service: ~$0.20 cents per share

PERMIT STATUS

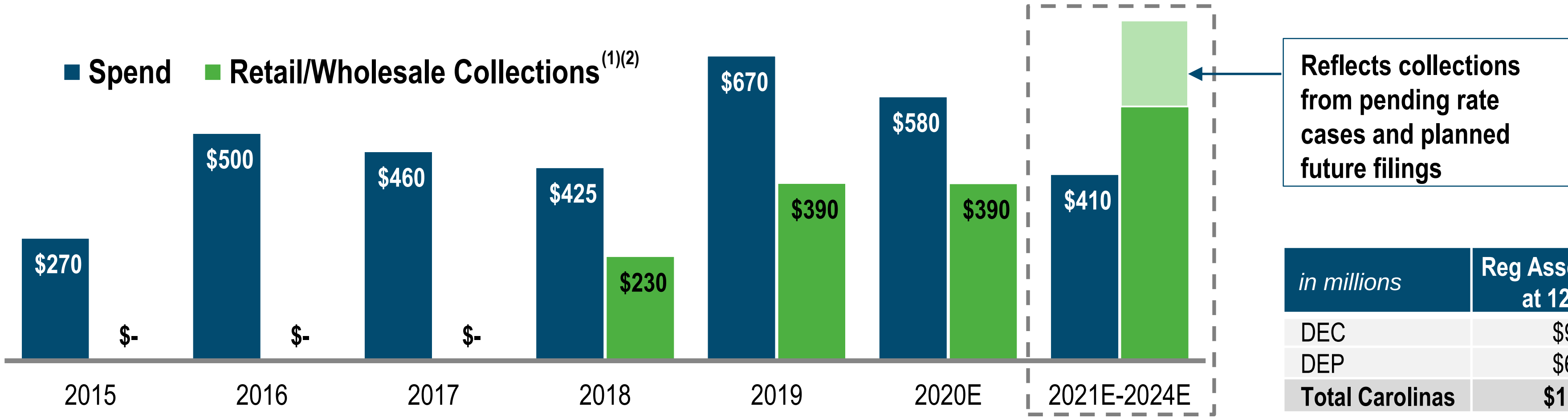
	Status/expected resolution	Agency
Appalachian Trail	SCOTUS oral arguments Feb 24th / decision by June 2020	U.S. Forest Service
Biological Opinion	In process / reissuance mid-2020	U.S. Fish and Wildlife Services (USFWS)
Buckingham County	Evaluating alternatives / reissuance 2H2020	Virginia Air Control Board
Nationwide 12	Voluntarily remanded / reissuance mid-2020	U.S. Army Corps of Engineers
Blue Ridge Crossing	Voluntarily remanded / reissuance 2H2020	U.S. National Park Service

COMMITTED TO BRINGING LOW-COST NATURAL GAS TO UNDERSERVED SOUTHEAST

(1) Represents total project cost, of which Duke Energy's share is 47%. Excludes AFUDC
(2) Excludes financing costs at the holding company associated with the project

Coal ash settlement provides clarity on closure method and costs

- NCDEQ issued order April 1, 2019 requiring remaining 9 low risk basins be fully excavated
- Settlement reached with NCDEQ and community groups on December 31, 2019:
  - ~70% of remaining ash at 7 of the 9 basins to be excavated, with ash moved to on-site lined landfills
  - Parties agreed to settle and dismiss pending litigation; NCDEQ and community groups will not challenge the reasonableness, prudence, public interest or legal requirement of Settlement obligations
  - NCDEQ will expeditiously review and act on all applications by Duke Energy for necessary permits, and cooperate with Duke Energy's efforts to extend deadlines imposed by the Federal CCR rule, as necessary
- Reduces incremental closure costs by approximately $1.5 billion from April 1, 2019 order:
  - Now estimate total closure costs of $8 to $9 billion in the Carolinas
  - $2.3 billion spent through 2019; majority of remaining expenditures to occur over next 15-20 years



in millions	Reg Asset balance at 12/31/19
DEC	$970
DEP	$605
Total Carolinas	**$1,575**

ANNUAL COLLECTIONS FORECASTED TO APPROXIMATE OR EXCEED SPEND ON CAROLINAS COAL ASH REMEDIATION

(1) *Comprised of annualized revenue requirement for DEC-NC 2018 rate case (~$120M effective 8/1/2018), DEP-NC 2018 rate case ($50M effective 3/15/2018), DEC-SC and DEP-SC 2019 rate cases (combined $20M effective 6/1/2019); and annualized revenue requirement requested in current DEC-NC ($100M effective 8/1/2020) and DEP-NC ($120M effective 9/1/2020) rate cases; as well as annual wholesale recoveries that average $150M 2018-2020E.*

(2) *Excludes additional recovery amounts expected in SC*

Commercial renewables

Happy Jack Wind Farm; Laramie County, WY

KEY ASSUMPTIONS

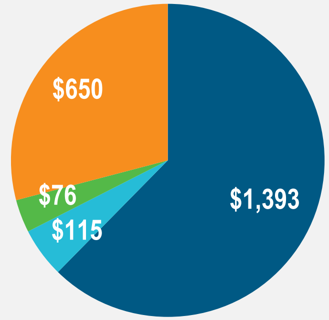
- Commercial renewables segment income relatively flat over the five-year plan (2020-2024) at approximately $200-$250 million per year
- Line-of-sight to all net income prospects for 2020; and ~60% of the five-year plan (2020-2024)
- Abundant opportunities exist to fill the approximately 200-300MW per year of solar growth projects expected to be placed in service
- Significant portion of earnings from tax equity solar projects recognized over 3-5 years
- Expect to continue to utilize tax equity financing
- Project returns solidly above internal hurdle rates for these types of investments

2019 performance and 2020 guidance supplemental information

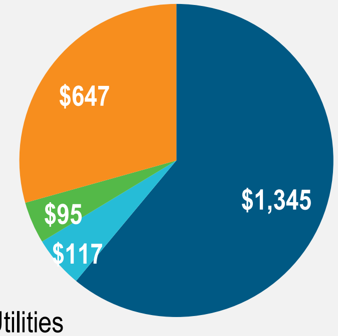
Key 2020 adjusted earnings guidance assumptions

($ in millions)	Orig. 2019 Assumptions	2019 Actual	2020 Assumptions
Adjusted segment income/(expense) (1):			
Electric Utilities & Infrastructure	$3,480	$3,509	$3,640
Gas Utilities & Infrastructure	$375	$451	$530
Commercial Renewables	$230	$198	$240
Other	($440)	($452)	($540)
Duke Energy Consolidated	$3,645	$3,706	$3,870
Additional consolidated information:			
Effective tax rate including noncontrolling interests and preferred dividends and excluding special items	12-14%	12.2%	11-13%
AFUDC equity (excludes ACP)	$168	$139	$138
Capital expenditures (2)(3)	$11,100	$11,875	$11,825
Weighted-average shares outstanding - basic	~729 million	729 million	~737 million

2020 Interest Expense Assumption
(Consolidated Total $2,234)



2019 Interest Expense
(Consolidated Total $2,204)



(1) Adjusted net income for 2020 assumptions is based upon the midpoint of the adjusted EPS guidance range of $5.05 to $5.45
(2) Includes debt AFUDC and capitalized interest
(3) 2019 Actual includes coal ash closure spend of ~$730 million that was included in operating cash flows and ~$130 million funded under the ACP revolving credit facility; excludes tax equity funding of Commercial Renewables projects of ~$430 million. 2020 Assumptions include ~$750 million of projected coal ash closure spend and $500 million projected to be funded under the ACP revolving credit facility

Electric utilities quarterly weather impacts

Weather segment income to normal:	2019			2018		
	Pretax impact	Weighted avg. shares	EPS impact favorable / (unfavorable)	Pretax impact	Weighted avg. shares	EPS impact favorable / (unfavorable)
First Quarter	($55)	727	($0.06)	$10	701	$0.01
Second Quarter	$80	728	$0.08	$90	704	$0.10
Third Quarter(1)	$145	729	$0.15	$55	714	$0.05
Fourth Quarter	$30	731	$0.03	$60	716	$0.06
Year-to-Date(1)(2)	$200	729	$0.20	$215	708	$0.22

4Q 2019	Duke Energy Carolinas		Duke Energy Progress		Duke Energy Florida		Duke Energy Indiana		Duke Energy Ohio/KY	
Heating degree days / Variance from normal	1,143	(8.9%)	1,000	(11.6%)	105	(46.8%)	1,991	1.0%	1,766	(4.1%)
Cooling degree days / Variance from normal	94	161.5%	118	109.7%	674	43%	37	135.9%	49	172.2%

4Q 2018	Duke Energy Carolinas		Duke Energy Progress		Duke Energy Florida		Duke Energy Indiana		Duke Energy Ohio/KY	
Heating degree days / Variance from normal	1,333	5.9%	1,128	(0.7%)	192	(2.9%)	2,090	6.1%	1,916	4%
Cooling degree days / Variance from normal	115	243.9%	143	161.2%	612	31.6%	83	433.6%	93	449.1%

(1) *2018 includes an unfavorable ~$15 million or $0.01/share impact from Hurricane Florence*
(2) *Year-to-date amounts may not foot due to differences in weighted-average shares outstanding and/or rounding.*

Key 2020 earnings sensitivities

Driver		EPS Impact
Electric Utilities & Infrastructure	1% change in earned return on equity	+/- $0.52
	$1 billion change in rate base	+/- $0.07
	1% change in volumes(1)	+/- $0.15
Gas Utilities & Infrastructure	1% change in earned return on equity	+/- $0.07
	$200 million change in rate base	+/- $0.01
	1% change in number of new customers	+/- $0.01
Consolidated	1% change in interest rates(2)	+/- $0.10

Note: EPS amounts based on forecasted 2020 basic share count of ~737 million shares

(1) Assumes 1% change across all customer classes; EPS impact for the industrial class is lower due to lower margins
(2) Based on average variable-rate debt outstanding throughout the year

DUKE ENERGY.

Regulated utilities end of year earnings base[1]

Electric Utilities Earnings Base

($ in billions)	2019A	2020E	2021E	2022E	2023E	2024E
Duke Energy Carolinas	$25.3	$26.9	$28.7	$30.3	$32.1	$33.9
Duke Energy Progress	17.9	18.6	18.4	19.5	20.7	21.6
Duke Energy Florida	14.1	15.5	16.6	17.7	18.8	20.2
Duke Indiana	8.5	9.1	9.2	9.4	9.9	10.2
Duke Ohio – Electric	2.9	3.1	3.3	3.5	3.6	3.8
Duke Kentucky – Electric	1.0	1.1	1.1	1.2	1.3	1.3
Electric Utilities Total[2]	**$69.7**	**$74.3**	**$77.4**	**$81.6**	**$86.5**	**$90.9**

Gas Utilities Earnings Base

($ in billions)	2019A	2020E	2021E	2022E	2023E	2024E
Piedmont	$5.2	$5.7	$6.2	$6.7	$7.3	$7.8
Duke Energy Ohio – Gas	1.5	1.7	1.8	1.9	2.0	2.0
Duke Energy Kentucky - Gas	0.4	0.5	0.5	0.5	0.5	0.5
Natural Gas Transmission	2.0	3.1	4.0	4.0	3.8	3.6
Gas Utilities Total[2]	**$9.1**	**$10.9**	**$12.5**	**$13.1**	**$13.6**	**$13.9**

(1) Illustrative earnings base for presentation purposes only and includes retail and wholesale; Amounts as of the end of each year shown; Projected earnings base = prior period earnings base + capex – D&A – deferred taxes
(2) Totals may not foot due to rounding

Capital expenditures profile[(1)]

DUKE ENERGY.

($ in millions)

Electric Utilities & Infrastructure	**2019A**	**2020E**	**2021E**	**2022E**	**2023E**	**2024E**	**2020 - 2024**
Electric Generation[(2)]	1,417	1,500	1,375	1,475	1,600	1,775	7,725
Electric Transmission	1,070	1,325	1,350	1,425	1,525	1,200	6,825
Electric Distribution	2,574	2,650	3,125	3,575	3,875	3,550	16,775
Environmental & Other[(3)]	1,019	975	725	750	600	500	3,550
Electric Utilities & Infrastructure Growth Capital	**$ 6,079**	**$ 6,450**	**$ 6,575**	**$ 7,225**	**$ 7,600**	**$ 7,025**	**$ 34,875**
Maintenance	2,957	2,275	1,925	2,050	2,225	2,250	10,725
Total Electric Utilities & Infrastructure Capital	**$ 9,036**	**$ 8,725**	**$ 8,500**	**$ 9,275**	**$ 9,825**	**$ 9,275**	**$ 45,600**
Commercial Renewables[(4)]	965	550	600	400	300	300	2,150
Total Commercial Renewables Capital	**$ 965**	**$ 550**	**$ 600**	**$ 400**	**$ 300**	**$ 300**	**$ 2,150**
Midstream Pipelines[(5)]	321	1,100	925	125	-	-	2,150
LDC - Non-Rider	376	425	350	325	325	300	1,725
LDC - Rider	318	275	350	400	425	300	1,750
Gas Utilities & Infrastructure Growth Capital	**$ 1,015**	**$ 1,800**	**$ 1,625**	**$ 850**	**$ 750**	**$ 600**	**$ 5,625**
Maintenance	639	475	325	300	275	325	1,700
Total Gas Utilities & Infrastructure Capital	**$ 1,654**	**$ 2,275**	**$ 1,950**	**$ 1,150**	**$ 1,025**	**$ 925**	**$ 7,325**
Other[(6)]	219	275	275	325	275	250	1,400
Total Duke Energy	**$ 11,875**	**$ 11,825**	**$ 11,325**	**$ 11,150**	**$ 11,425**	**$ 10,750**	**$ 56,475**

(1) *Amounts include AFUDC debt or capitalized interest. Totals may not foot due to rounding*
(2) *Includes nuclear fuel of ~$2.1B from 2020-2024*
(3) *2019 actual amounts include ~$730 million in coal ash closure spending that was included in operating cash flows*
(4) *Amounts are net of assumed tax equity financings*
(5) *Investment level will depend upon how the project and Duke investment are financed; 2019 actual amounts include ~$130 million funded under the ACP revolving credit facility*
(6) *Primarily IT and real estate related costs*

Capital expenditures by utility[1]

($ in millions)

Duke Energy Carolinas		2019A		2020E		2021E		2022E		2023E		2024E		2020 - 2024
Electric Generation	$	535	$	725	$	525	$	425	$	575	$	850	$	3,100
Electric Transmission		197		350		400		425		375		350		1,900
Electric Distribution		809		925		1,475		1,300		1,600		1,475		6,775
Environmental & Other (2)		409		325		350		400		300		250		1,625
Duke Energy Carolinas Growth Capital	**$**	**1,949**	**$**	**2,325**	**$**	**2,750**	**$**	**2,550**	**$**	**2,850**	**$**	**2,925**	**$**	**13,400**
Maintenance		1,041		775		725		875		875		825		4,075
Total Duke Energy Carolinas Capital	**$**	**2,990**	**$**	**3,100**	**$**	**3,475**	**$**	**3,425**	**$**	**3,725**	**$**	**3,750**	**$**	**17,475**

Duke Energy Progress		2019A		2020E		2021E		2022E		2023E		2024E		2020 - 2024
Electric Generation	$	372	$	300	$	450	$	750	$	725	$	625	$	2,850
Electric Transmission		129		125		175		175		375		200		1,050
Electric Distribution		603		650		650		750		750		650		3,450
Environmental & Other (3)		485		450		225		225		200		200		1,300
Duke Energy Progress Growth Capital	**$**	**1,588**	**$**	**1,525**	**$**	**1,500**	**$**	**1,900**	**$**	**2,050**	**$**	**1,675**	**$**	**8,650**
Maintenance		912		600		600		525		575		575		2,875
Total Duke Energy Progress Capital	**$**	**2,500**	**$**	**2,125**	**$**	**2,100**	**$**	**2,425**	**$**	**2,625**	**$**	**2,250**	**$**	**11,525**

(1) Amounts include AFUDC debt. Totals may not foot due to rounding
(2) 2019 actual amounts include ~$278 million in coal ash closure spending that was included in operating cash flows
(3) 2019 actual amounts include ~$392 million in coal ash closure spending that was included in operating cash flows

Capital expenditures by utility (continued)[1]

($ in millions)

Duke Energy Florida	2019A	2020E	2021E	2022E	2023E	2024E	2020 - 2024
Electric Generation	$ 401	$ 325	$ 325	$ 200	$ 200	$ 200	$ 1,250
Electric Transmission	425	575	450	400	300	300	2,025
Electric Distribution	471	500	525	925	925	925	3,800
Environmental & Other (2)	8	-	-	-	-	-	-
Duke Energy Florida Growth Capital	**$ 1,306**	**$ 1,400**	**$ 1,300**	**$ 1,525**	**$ 1,425**	**$ 1,425**	**$ 7,075**
Maintenance	582	475	450	425	525	525	2,400
Total Duke Energy Florida Capital	**$ 1,888**	**$ 1,875**	**$ 1,750**	**$ 1,950**	**$ 1,950**	**$ 1,950**	**$ 9,475**

Duke Energy Indiana	2019A	2020E	2021E	2022E	2023E	2024E	2020 - 2024
Electric Generation	$ 94	$ 125	$ 75	$ 25	$ 100	$ 100	$ 425
Electric Transmission	129	125	225	325	375	250	1,300
Electric Distribution	313	225	175	300	325	225	1,250
Environmental & Other (3)	82	200	150	125	100	50	625
Duke Energy Indiana Growth Capital	**$ 618**	**$ 675**	**$ 625**	**$ 775**	**$ 900**	**$ 625**	**$ 3,600**
Maintenance	311	300	100	150	175	225	950
Total Duke Energy Indiana Capital	**$ 928**	**$ 975**	**$ 725**	**$ 925**	**$ 1,075**	**$ 850**	**$ 4,550**

(1) Amounts include AFUDC debt. Totals may not foot due to rounding
(2) 2019 actual amounts include ~$2 million in coal ash closure spending that was included in operating cash flows
(3) 2019 actual amounts include ~$52 million in coal ash closure spending that was included in operating cash flows

Capital expenditures by utility (continued)(1)

($ in millions)

Duke Energy OH/KY Electric		2019A		2020E		2021E		2022E		2023E		2024E		2020 - 2024
Electric Generation	$	14	$	25	$	-	$	75	$	-	$	-	$	100
Electric Transmission		189		150		100		100		100		100		550
Electric Distribution		338		300		250		250		225		225		1,250
Environmental & Other (2)		36		-		-		-		-		-		-
Duke Energy OH/KY Growth Capital	**$**	**578**	**$**	**475**	**$**	**350**	**$**	**425**	**$**	**325**	**$**	**325**	**$**	**1,900**
Maintenance		111		125		50		75		75		100		425
Total Duke Energy OH/KY Electric Capital	**$**	**689**	**$**	**600**	**$**	**400**	**$**	**500**	**$**	**400**	**$**	**425**	**$**	**2,325**

Duke Energy OH/KY Gas		2019A		2020E		2021E		2022E		2023E		2024E		2020 - 2024
LDC - Non-Rider		65		100		150		75		75		75		475
LDC - Rider		20		25		25		-		-		-		50
Duke Energy OH/KY Gas Growth Capital	**$**	**85**	**$**	**125**	**$**	**175**	**$**	**75**	**$**	**75**	**$**	**75**	**$**	**525**
Maintenance		187		175		125		100		100		100		600
Total Duke Energy OH/KY Gas Capital	**$**	**272**	**$**	**300**	**$**	**300**	**$**	**175**	**$**	**175**	**$**	**175**	**$**	**1,125**

Piedmont		2019A		2020E		2021E		2022E		2023E		2024E		2020 - 2024
LDC - Non-Rider		310		325		200		250		250		225		1,250
LDC - Rider		298		250		325		400		425		300		1,700
Piedmont Growth Capital	**$**	**609**	**$**	**575**	**$**	**525**	**$**	**650**	**$**	**675**	**$**	**525**	**$**	**2,950**
Maintenance		452		300		200		200		175		225		1,100
Total Piedmont Capital	**$**	**1,061**	**$**	**875**	**$**	**725**	**$**	**850**	**$**	**850**	**$**	**750**	**$**	**4,050**

(1) Amounts include AFUDC debt. Totals may not foot due to rounding
(2) 2019 actual amounts include ~$8 million in coal ash closure spending that was included in operating cash flows

Environmental compliance expenditures

($ in millions)

Category	2020 – 2024
Coal ash closure	$2,775
All other environmental	$250
Total	**$3,025**

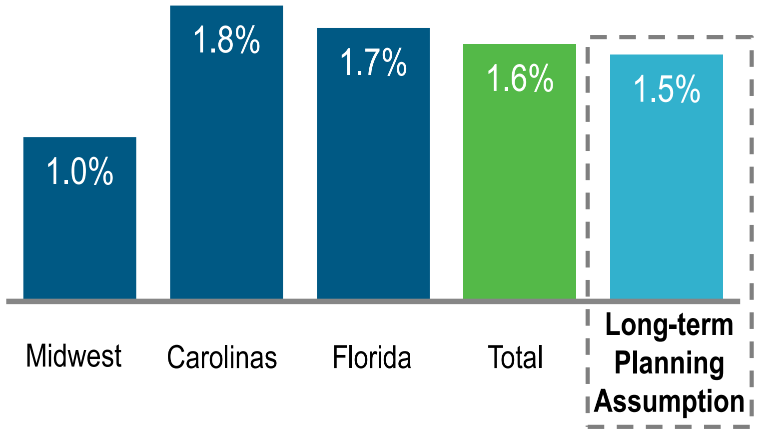
Coal Ash Closure Costs	Total Project Costs	Spend To Date[(1)]	2020 – 2024 Plan
Duke Energy Carolinas	$5,025	$1,228	$1,025
Duke Energy Progress	$3,650	$1,092	$1,200
Duke Energy Indiana	$1,100	$202	$530
Duke Energy Florida	$25	$2	$ --
Duke Energy Kentucky	$75	$23	$20
Total	**$9,875**	**$2,547**	**$2,775**

(1) *As of Dec. 31, 2019*

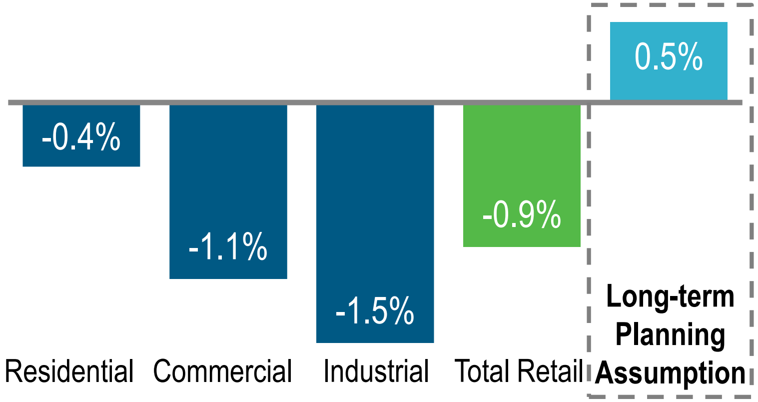
2019 Electric customer growth and weather-normal volume trends

DUKE ENERGY

ANNUAL GROWTH IN NUMBER OF RESIDENTIAL ELECTRIC CUSTOMERS



ROLLING 12-MONTH RETAIL ELECTRIC VOLUME GROWTH



RESIDENTIAL

- Increase in average number of customers in our attractive service territories drives long-term volume growth for electric and gas utilities
- Company-sponsored energy efficiency programs contributed to lower usage per customer

COMMERCIAL

- Weakness in big box retail stores resulting from store closures and energy efficiency penetration
- Data center expansion continues to be a positive

INDUSTRIAL

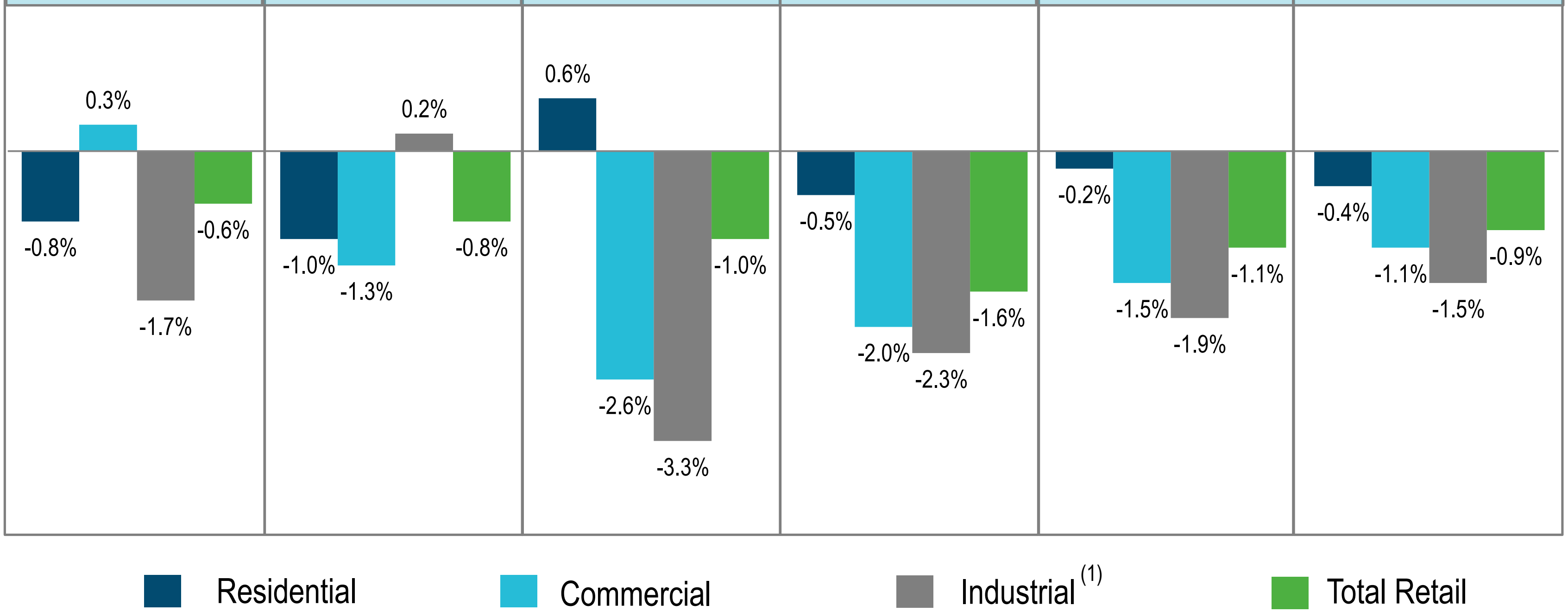
- Manufacturing contractions contributed to weak volumes
- Expect improvement as customer-specific production declines and temporary outages reverse

ENERGY EFFICIENCY RIDER REVENUES PARTIALLY OFFSET LOAD RESULTS

Weather normalized volume trends, by electric jurisdiction

Rolling Twelve Months, as of Dec. 31, 2019

Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio/Kentucky	Electric Utilities
Estimated impact of utility sponsored energy efficiency efforts on residential sales					
1.0% to 1.5%	**0.5% to 1.0%**	**n/a**	**0.5% to 1.0%**	**1.5% to 2.0%**	**~1.0%**

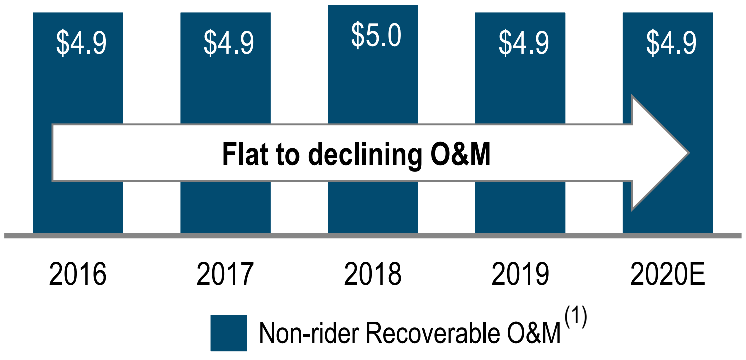


UTILITY ENERGY EFFICIENCY PROGRAMS COMPENSATE THE COMPANY FOR INVESTMENTS AND LOST REVENUES

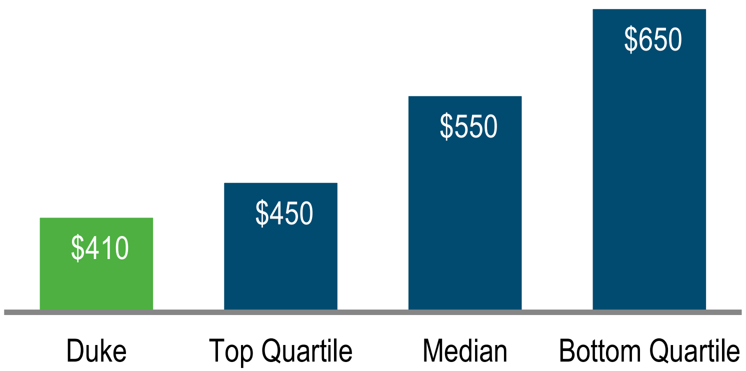
(1) Electric Utilities industrial results have been impacted by production interruptions at a couple of large customers

Strong O&M cost management

O&M COST MANAGEMENT
($ IN BILLIONS)



TOP QUARTILE O&M PROFILE
(Non-Generation O&M $/Customer(2))



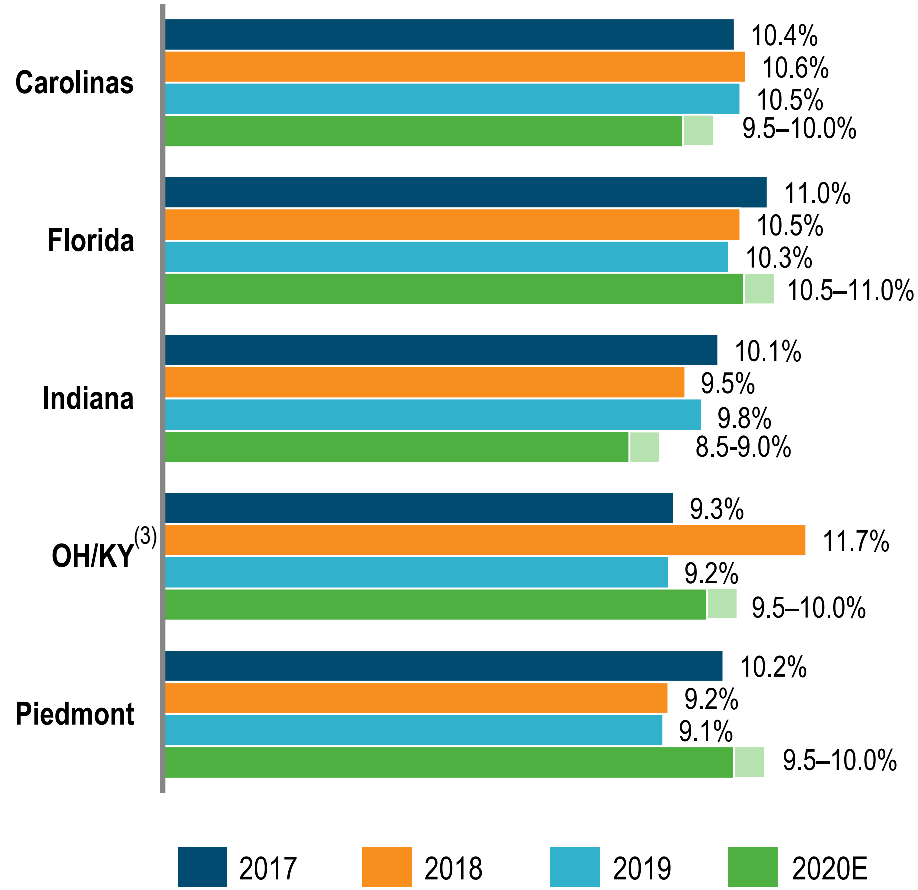
TOP TIER COST MANAGEMENT CONTINUES

- Outstanding track record of cost management
- Since 2015, we have kept non-recoverable O&M flat
  - Includes absorbing ~$300 million of O&M from the Piedmont acquisition in 2016, in addition to offsetting wage and salary increases and general inflation
- Leveraging increased cost flexibility to keep non-rider recoverable O&M flat despite inflation
- Employing data analytics and digital capabilities to enhance decision making and prioritization
- State of the art Innovation Center – Optimist Hall
- Utilizing cost saving opportunities as a lever to meet business commitments
- Applying our size and scale to transform operational capabilities

(1) Non-rider Recoverable O&M excludes special items and other non-recoverable charges incurred. For a reconciliation to GAAP O&M see accompanying materials at www.duke-energy.com/investors
(2) S&P Global Market Intelligence; SNL Energy Data as sourced from FERC Form 1. Data from over 128 U.S. Regulated Utilities with more than 100,000 customers, rounded.

Managing regulatory lag and customer rate impacts

ADJUSTED BOOK ROEs(1)



COMPETITIVE CUSTOMER RATES(2)

DELIVERING COMPETITIVE RETURNS FOR INVESTORS WHILE KEEPING RATES WELL BELOW THE NATIONAL AVERAGE FOR CUSTOMERS

(1) *Adjusted book ROEs exclude special items and are based on average book equity less Goodwill. Adjusted ROEs also include wholesale and are not adjusted for the impacts of weather. Regulatory ROEs will differ from Adjusted Book ROEs*
(2) *Residential customer rates. Typical bill rates (¢/kWh) in effect as of July 1, 2019. Vertically integrated utilities only. Source: EEI Typical Bills and Avg. Rates Report, Winter 2019*
(3) *Combined electric and gas utilities*

DUKE ENERGY

Renewables projects announcements

REGULATED

Site	Solar Megawatts	COD	Location
Lake Placid	45	Q4 2019	FL
Trenton	74.9	Q4 2019	FL
DeBary	74.5	Q1 2020	FL
Columbia	74.9	Q1 2020	FL
Twin Rivers	74.9	Q4 2020	FL
Santa Fe	74.9	Q4 2020	FL
Catawba County(1)	69	2020	NC (DEC)
Gaston County(1)	25	2020	NC (DEC)
PPA projects(1)(2)	331	2020/2021	NC/SC
Total	**844**		

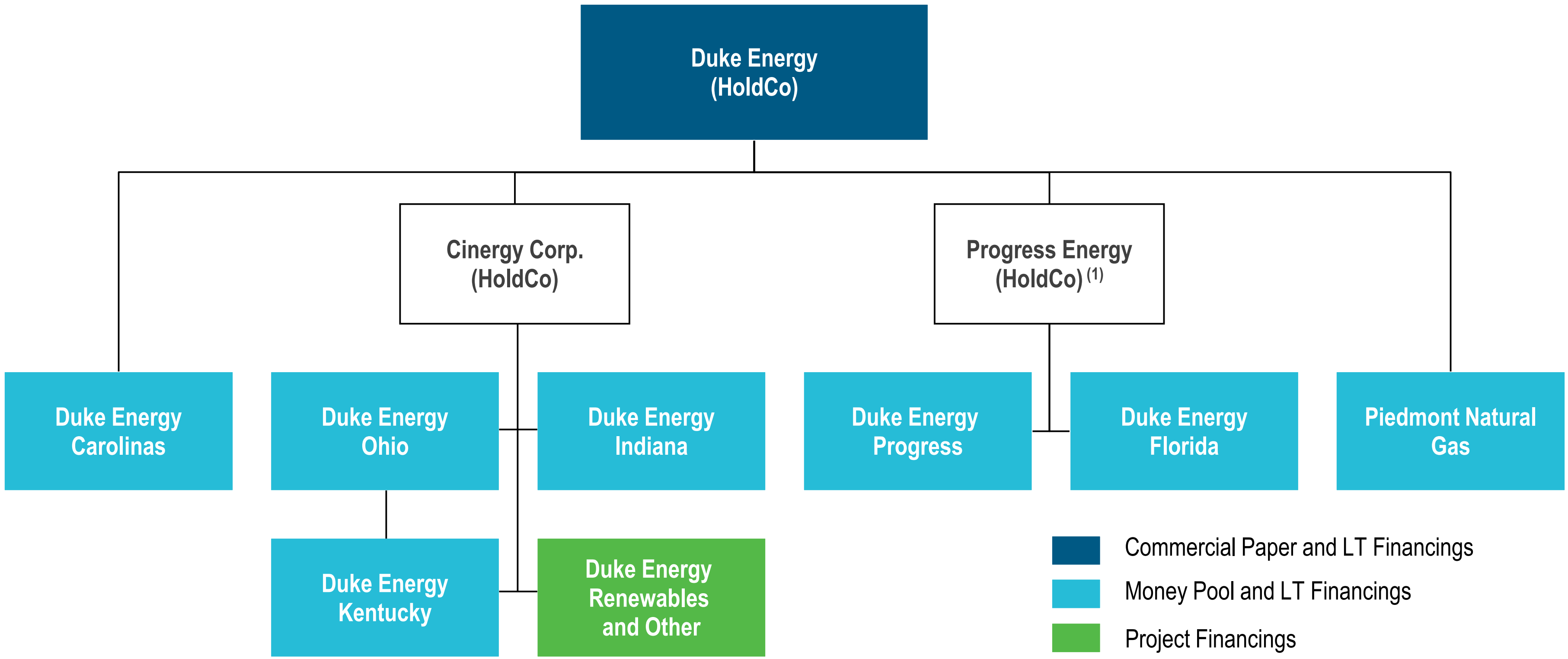
COMMERCIAL RENEWABLES

Site	Megawatts				COD	Location
	Solar	Wind	Fuel Cell	Total		
Cleveland County(1)	50	-	-	50	2020	NC
Surry County(1)	23	-	-	23	2020	NC
Cabarrus County(1)	23	-	-	23	2020	NC
Rosamond	150	-	-	150	Q2 2019	CA
Lapetus	100	-	-	100	Q4 2019	TX
Palmer	60	-	-	60	Q1 2020	CO
Holstein	200	-	-	200	Mid-2020	TX
Rambler	200	-	-	200	Mid-2020	TX
Mesteno	-	200	-	200	Q4 2019	TX
Frontier II	-	350	-	350	2020	OK
Maryneal	-	180	-	180	2020	TX
Bloom Energy	-	-	37	37	2019/2020	Various
Total	**806**	**730**	**37**	**1,573**		

(1) Projects that cleared the first RFP under HB589 (521 MW in total of which Duke Energy owns 190MW). Dates may vary depending upon local approvals and any construction delays
(2) Projects procured on behalf of customers but not owned by Duke Energy

Financing assumptions

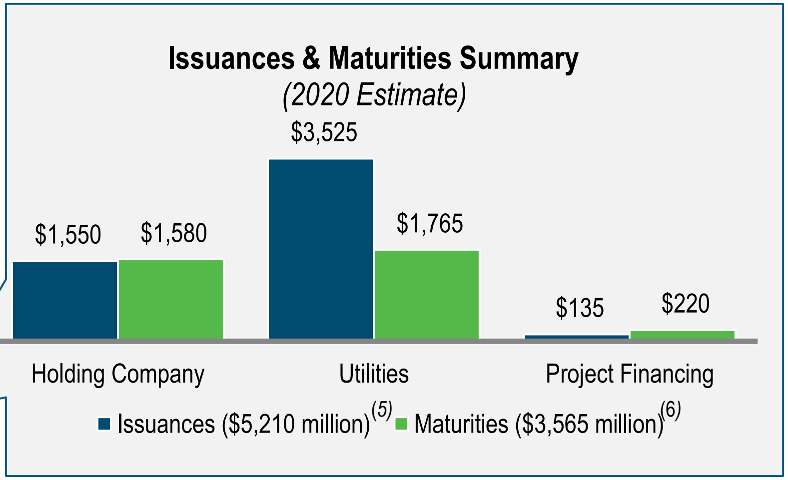
Simplified financing structure



(1) Progress Energy HoldCo has long-term debt outstanding, but no future common equity issuance is planned at this financing entity

Forecasted 2020 summary cash flows[1]

Adjusted net income[2]	$ 3,870
Depreciation & amortization	5,470
Deferred and accrued taxes[3]	805
Other sources / (uses), net[4]	(235)
Primary sources	**9,910**
Capital expenditures	(11,825)
Dividends (subject to Board of Directors discretion)	(2,800)
Primary uses	**(14,625)**
Uses in excess of sources	(4,715)
Net Change in debt	1,645
Common equity issuance	2,985
Net Change in Cash	**$ (85)**



(1) *Financing plan is subject to change, based on circumstances encountered throughout the year*
(2) *Based upon the midpoint of the 2020 guidance range*
(3) *Includes expected AMT refund of ~$275 million*
(4) *Includes changes in working capital and AFUDC equity*
(5) *Includes junior subordinated debt/equity content security issuances*
(6) *Includes net changes in Commercial Paper*

2020 Financing plan[1]

DUKE ENERGY.

Issuer	Planned Amount ($ in millions)	Security	Completed ($ in millions)	Date Issued	Term	Rate	2020 Maturities[4]
Holding Company	$1,000 - $1,500	Debt/hybrid securities	-	-	-	-	$330
Holding Company	$500	Common Equity (ATM/DRIP)[2]	$0 – ATM $5 – DRIP	YTD	-	-	-
DE Carolinas	$800 - $1,000	Senior Debt	$500 $400	Jan. 2019	10-year 30-year[3]	Fixed – 2.45% Fixed – 3.20%	$450
DE Progress	$500 - $700	Senior Debt	-	-	-	-	$1,000
DE Florida	$400 - $600	Senior Debt	-	-	-	-	$500
DE Indiana	$450 - $650	Senior Debt	-	-	-	-	$500
DE Ohio	$300 - $500	Senior Debt	-	-	-	-	-
Piedmont	$300 - $500	Senior Debt	-	-	-	-	-
DE Kentucky	$50 - $70	Senior Debt	-	-	-	-	-

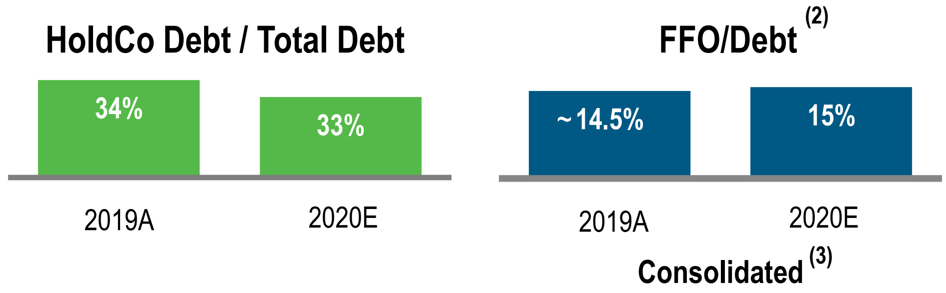
(1) Excludes financings at Commercial Renewables and other non-regulated entities
(2) The common equity figure for 2020 represents new issuance of common stock via the company's DRIP and ATM program. Additionally, the Company intends to physically settle the ~$2.5 billion equity forward transaction that priced in November 2019 by December 31, 2020.
(3) Reopened the existing 3.20% 2049s
(4) Excludes amortization of noncash purchase accounting adjustments and CR3 securitization

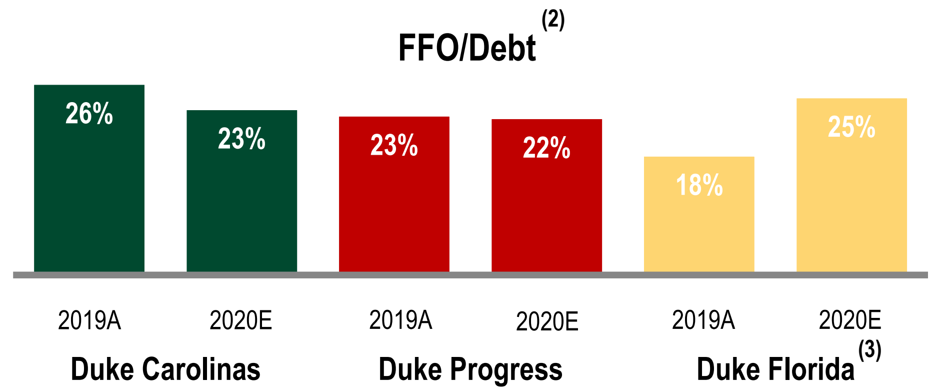
Credit ratings (as of February 13, 2020) and cash flow metrics[(1)]

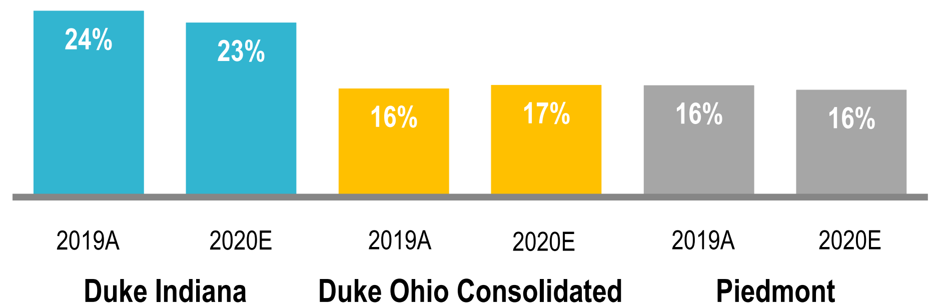
Rated Issuers

	Moody's	S&P
DUKE ENERGY CORPORATION	Stable	Stable
Senior Unsecured Debt	Baa1	BBB+
Commercial Paper	P-2	A-2
PROGRESS ENERGY, INC.	Stable	Stable
Senior Unsecured Debt	Baa1	BBB+
DUKE ENERGY CAROLINAS, LLC	Stable	Stable
Senior Secured Debt	Aa2	A
Senior Unsecured Debt	A1	A-
DUKE ENERGY PROGRESS, LLC	Stable	Stable
Senior Secured Debt	Aa3	A
DUKE ENERGY FLORIDA, LLC	Stable	Stable
Senior Secured Debt	A1	A
Senior Unsecured Debt	A3	A-
DUKE ENERGY INDIANA, LLC	Stable	Stable
Senior Secured Debt	Aa3	A
Senior Unsecured Debt	A2	A-
DUKE ENERGY OHIO, INC.	Stable	Stable
Senior Secured Debt	A2	A
Senior Unsecured Debt	Baa1	A-
DUKE ENERGY KENTUCKY, INC.	Stable	Stable
Senior Unsecured Debt	Baa1	A-
PIEDMONT NATURAL GAS, INC.	Stable	Stable
Senior Unsecured Debt	A3	A-

Note: Fitch announced on January 21, 2020 its intention to withdraw ratings on Duke Energy Corp within 30 days due to commercial reasons







(1) Amounts do not include all adjustments that may be made by the rating agencies
(2) Key adjustments within the computation include the removal of coal ash remediation spending from FFO, and the adjusted debt balance excludes purchase accounting adjustments
(3) Assumes securitization treated as off credit

Liquidity summary (as of Dec. 31, 2019)

($ in millions)

	Duke Energy	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio	Duke Energy Kentucky	Piedmont Natural Gas	Total
Master Credit Facility [1]	$ 2,650	$ 1,500	$ 1,250	$ 800	$ 600	$ 450	$ 150	$ 600	$ 8,000
Less: Notes payable and commercial paper [2]	(1,119)	(325)	(207)	-	(176)	(200)	(96)	(414)	(2,537)
Coal Ash Set-Aside [3]	-	(250)	(250)	-	-	-	-	-	(500)
Outstanding letters of credit (LOCs)	(42)	(4)	(2)	-	-	-	-	(2)	(50)
Tax-exempt bonds	-	-	-	-	(81)	-	-	-	(81)
Available capacity	$ 1,489	$ 921	$ 791	$ 800	$ 343	$ 250	$ 54	$ 184	$ 4,832
Funded Revolver and Term Loan [4]	$ 1,000		$ 700						$ 1,700
Less: Borrowings Under Credit Facilities	(500)		(700)						(1,200)
Available capacity	$ 500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 500
Cash & short-term investments									277
Total available liquidity									**$ 5,609**

(1) Duke Energy's master credit facility supports Tax-Exempt Bonds, LOCs and the Duke Energy CP program of $6 billion. The CP program was increased to $6.0 billion (previously $4.85B) on 11/15/19.
(2) Includes permanent layer of commercial paper of $625 million, which is classified as long-term debt
(3) Duke Energy Carolinas and Duke Energy Progress are required to each maintain $250 million of available capacity under the Master Credit Facility as security to meet obligations under plea agreements reached with the U.S. Department of Justice in 2015 related to violations at North Carolina facilities with ash basins. This requirement expires in May 2020.
(4) Borrowings under these facilities will be used for general corporate purposes.

2020 Pension funding and costs

- On a consolidated basis, Duke Energy pension plans funding status is 107% as of 12/31/2019 on a PBO basis
- Duke Energy's pension funding policy:
  - Duke Energy's policy is to fund amounts on an actuarial basis to provide assets sufficient to meet benefit payments to be paid to plan participants
  - Duke plans have a targeted allocation of 58% fixed-income assets and 42% return-seeking assets

Pension Contributions *($ in millions)*	2018A	2019A	2020E
All plans	$141	$77	$0

- Key 2020 assumptions (as of Dec. 31, 2019):
  - Discount rate: 3.3% for 2020 (vs. 4.3% for 2019)
  - Expected long-term return of 6.85% on plan assets (flat to 2019 assumption)

Sustainability / Environmental Social and Governance (ESG)

Duke Energy's industry-leading climate plan

Companywide CO_2 Emissions Reduction Goals[1]

- ❑ Cut CO_2 emissions by at least 50% by 2030
- ❑ Attain net-zero CO_2 emissions by 2050

CO_2 Reductions Already Achieved[2]

- ✓ Exceeded 2025 reduction benchmarks agreed to by the U.S. for the Paris climate accord
- ✓ Met the 2030 CO_2 emission-reduction requirements of EPA's former Clean Power Plan almost 11 years early

PATH TO A LOW-CARBON FUTURE

- Collaborate and align with our states and stakeholders as we transform
- Accelerate transition to cleaner energy solutions
- Modernize our electric grid
- Continue to operate existing carbon-free technologies, including nuclear and renewables
- Advocate for sound public policy that advances technology and innovation

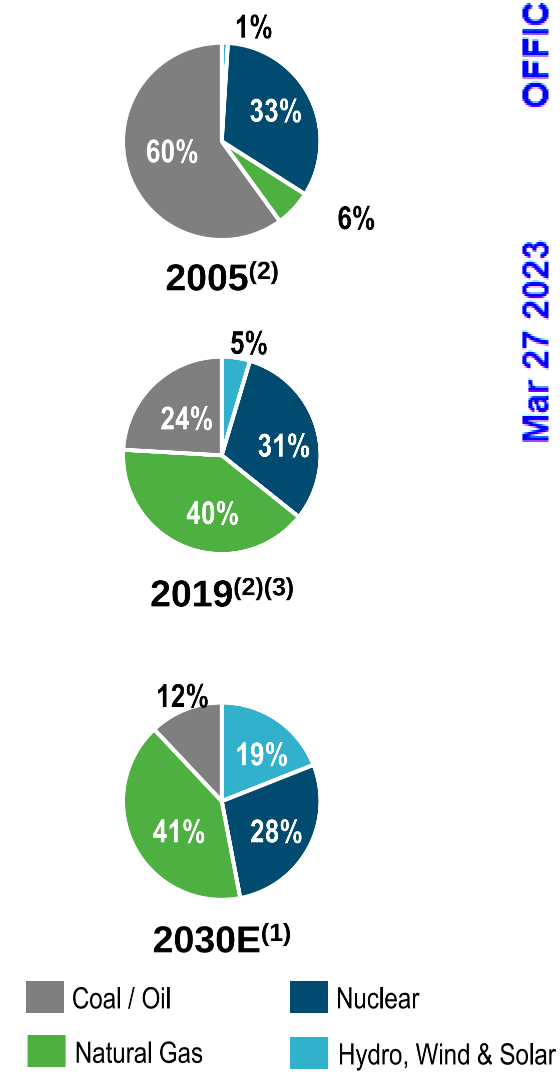
(1) From 2005 levels
(2) Achieved 39% reduction as of 2019

Environmental and climate accomplishments

SIGNIFICANT CARBON REDUCTIONS AND RENEWABLE POWER EXPANSION

- Since 2005, decreased CO_2 emissions by 39%, sulfur dioxide emissions by 97% and nitrogen oxides emissions by 79%[(1)]
- 51 coal units retired (~6.5 GW) since 2010
  - Plans to retire an additional ~0.9 GW of coal by 2024
  - Proposals in NC and IN for accelerated depreciation of ~7 GW of coal units
- Completed excavation of 12 ash basins, ~28 million tons of ash to fully lined facilities or recycled
- As of year-end 2019, owned or contracted 8,100 MW of renewables
- Targeting 1 trillion gallon reduction in water withdrawals by our generation fleet by 2030 (from 5.34 trillion gallons in 2016)
- Clear leader in energy efficiency savings in the Southeast

FUEL DIVERSITY (MWh OUTPUT)



(1) From 2005 levels. 2030 estimate and year to year reductions will be influenced by customer demand for electricity, weather, fuel and purchased power prices, and other factors
(2) 2005 and 2019 data based on Duke's ownership share of U.S. generation assets as of Dec. 31, 2019
(3) 2019 data excludes 9,400 GWh of purchased renewables, equivalent to ~4% of Duke's output

Social responsibility – commitment to safe and inclusive workplace

DUKE ENERGY.

SAFETY – OUR NUMBER ONE PRIORITY

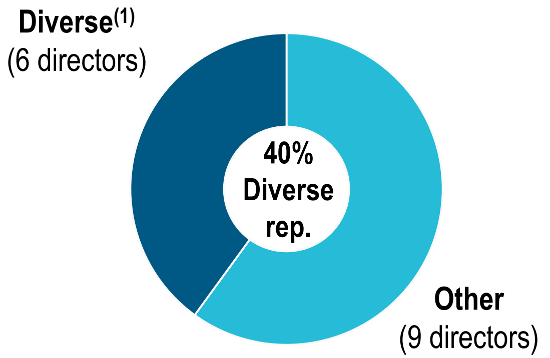
- Total Incident Case Rate (TICR) of 0.38 in 2019; one of the industry leaders for 5th year in a row

EMPLOYEES

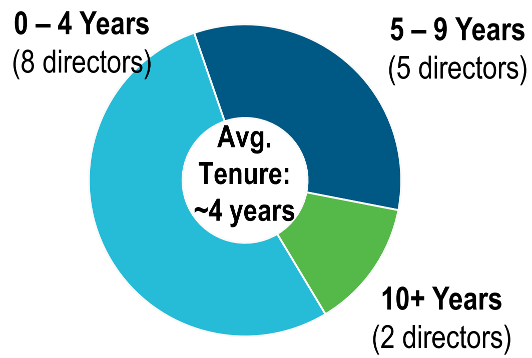
- Named one of Fortune's "World's Most Admired Companies" for 3rd consecutive year
- Named one of "America's Best Employers" by Forbes in 2019 for 2nd consecutive year
- Duke Energy was named to the Human Rights Campaign's 2020 "Best Place to Work for LGBTQ Equality" list with a perfect score of 100 percent in its Corporate Equality Index.
- Named one of the "50 Best Companies for Diversity" by Black Enterprise magazine in 2018
- Ranked 125 on Newsweek's 2020 list of 300 most responsible American companies, out of 2,000 companies analyzed

Governance and transparency

BOARD DIVERSITY



BOARD TENURE



- Dow Jones Sustainability Index for 14 years in a row
- Over a decade of annual Sustainability reports
- Climate Report issued in 2018 analyzes 2-degree scenario
  - Utilizes Task Force on Climate-related Financial Disclosures ("TCFD") framework
  - Updating Climate Report in 2020 to align with new climate goal
- EEI / AGA reporting templates provide investors greater uniformity and consistency in reporting of ESG metrics
- 2019 Winner of U.S. Transparency Award by Labrador Group for utilities
- Bloomberg ESG disclosure score of 57.4, the third-best score and in the top quartile of U.S. utilities[2]

GOVERNANCE

- Oversight of sustainability formally added to charter of the Corporate Governance Committee of the Duke Energy Board of Directors in 2018
- Received highest possible ISS Governance score

see more at: **www.duke-energy.com/our-company/sustainability**

(1) Racial, gender and ethnic diversity
(2) As of January 29, 2020

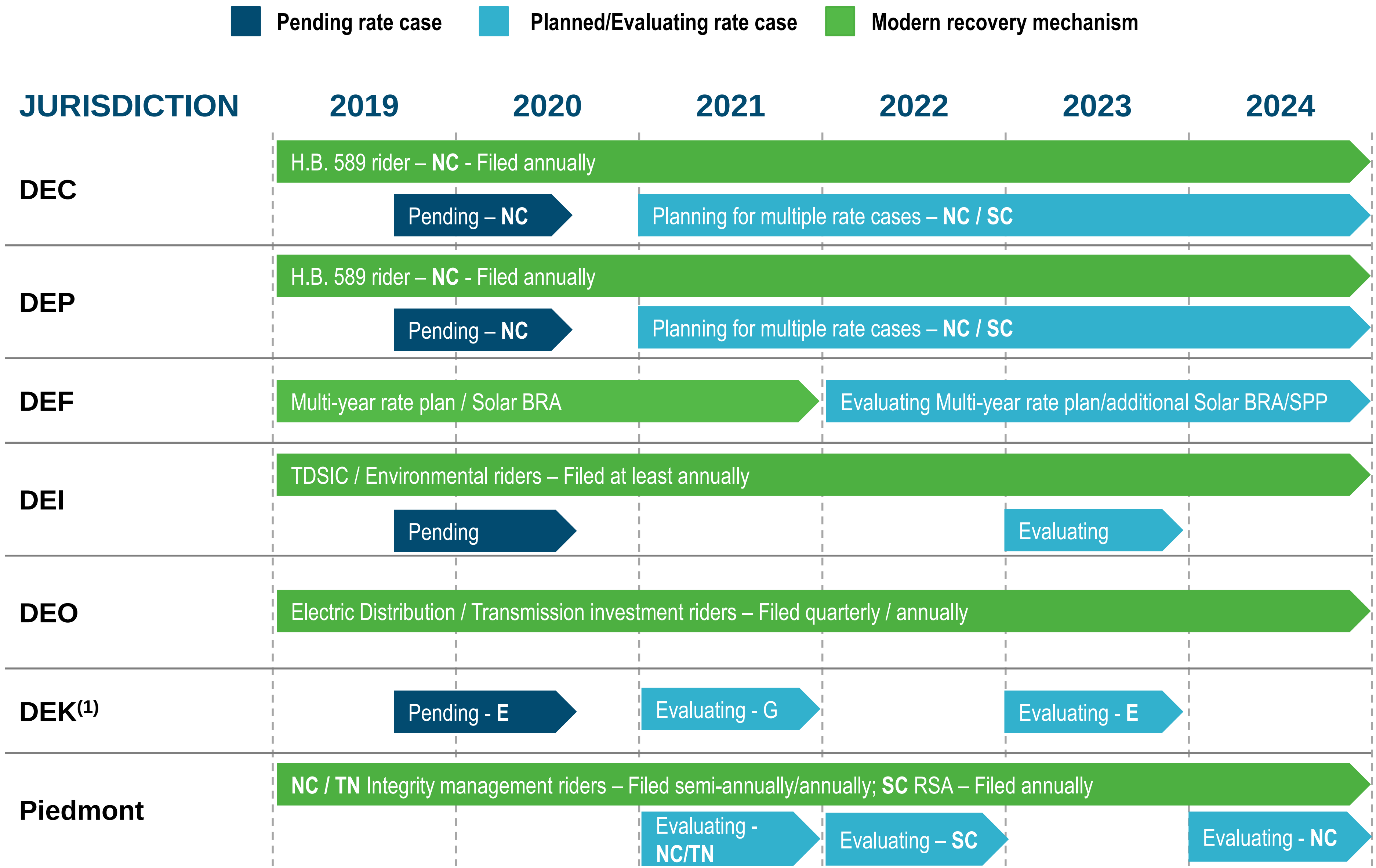
Regulatory overview

Update on general rate case activity

	FILING TYPE	DOCKET NO.	STATUS	KEY DRIVERS
DUKE ENERGY **CAROLINAS**	NC Base Rate Case filed Sep. 30, '19	E-7 Sub 1214	▪ Hearings scheduled Mar 23, '20 ▪ Requested new rates effective Aug. 1, '20	▪ ROE 10.3%; 53% equity cap. structure ▪ Grid investments, including AMI ▪ Dual fuel plant upgrades ▪ Accelerated depreciation for coal plants ▪ Storm costs(1) and coal ash
DUKE ENERGY **PROGRESS**	NC Base Rate Case filed Oct. 30, '19	E-2 Sub 1219	▪ Hearings scheduled May 4, '20 ▪ Requested new rates effective Sep. 1, '20	▪ ROE 10.3%; 53% equity cap. structure ▪ Grid investments, including AMI ▪ Western Carolinas Modernization Project ▪ Nuclear plant investments ▪ Accelerated depreciation for coal plants ▪ Storm costs(1) and coal ash
DUKE ENERGY **INDIANA**	Base Rate Case filed July 2, '19	No. 45253	▪ Hearings concluded Feb. 7, '20 ▪ Requested new rates effective mid-'20	▪ ROE 10.4%; 53% equity cap. structure ▪ Grid investments ▪ Accelerated depreciation for coal plants ▪ Coal ash costs ▪ Includes modernized regulatory mechanisms
DUKE ENERGY **KENTUCKY**	Base Rate Case filed Sep. 3, '19	2019-00271	▪ Hearings scheduled Feb. 19, '20 ▪ Requested new rates effective Q2 '20	▪ ROE 9.8%; 48% equity cap. structure ▪ Investments in distribution system to support localized load growth and dual fuel capability

(1) With passage of SB559 (legislation for storm securitization) DEC and DEP will seek to securitize these costs

Regulatory calendar



(1) *"E" denotes Electric, "G" denotes Gas*

Overview of state commissions by jurisdiction

	North Carolina	South Carolina	Florida	Indiana	Ohio	Kentucky	Tennessee
Number of Commissioners	7	7	5	5	5	3	5
Term (years)	6	4	4	4	5	4	6
Appointed/Elected	Appointed by Governor	Elected by the General Assembly	Appointed by Governor	Appointed by Governor	Appointed by Governor	Appointed by Governor	Appointed by Governor and Legislature
Chair *(Term Exp.)*	Charlotte Mitchell *(June 2023)*	Randy Randall (June 2020)	Gary Clark (January 2023)	Jim Huston (March 2021)	Sam Randazzo (April 2024)	Michael Schmitt (June 2023)	Robin Morrison (June 2020)
Other Commissioners *(Term Exp.)*	▪ Lyons Gray (June 2021) ▪ ToNola Brown-Bland (June 2023) ▪ Dan Clodfelter (June 2023) ▪ Floyd McKissick (June 2025) ▪ Kimberly Duffley (June 2025) ▪ Jeff Hughes (June 2025)	▪ Florence Belser (February 2023) ▪ Swain Whitfield (June 2020) ▪ Butch Howard (June 2020) ▪ G. O'Neal Hamilton (June 2020) ▪ Tom Ervin (June 2022) ▪ Justin Williams (June 2022)	▪ Art Graham (January 2022) ▪ Julie Brown (January 2023) ▪ Donald Polmann (January 2021) ▪ Andrew Fay (January 2022)	▪ David Ziegner (April 2023) ▪ David Ober (January 2024) ▪ Sarah Freeman (January 2022) ▪ Stephanie Krevda (April 2022)	▪ Lawrence Friedman (April 2020) ▪ Beth Trombold (April 2023) ▪ Dennis Deters (April 2021) ▪ Daniel Conway (April 2022)	▪ Robert Cicero (June 2020) ▪ Talina Mathews (June 2021)	▪ Kenneth Hill (June 2020) ▪ Herbert Hilliard (June 2023) ▪ John Hie (June 2024) ▪ David Jones (June 2024)

Current electric rate information by jurisdiction

	North Carolina	South[1] Carolina	Florida	Indiana	Ohio (Electric)	Kentucky (Electric)
Retail Rate Base	\$13.5 B [2] (DEC) \$8.2 B [2] (DEP)	\$5.4 B (DEC) \$1.5 B (DEP)	\$13.5 B [3]	\$7.1 B [4]	\$1.3 B (dist. only)	\$650 M [5]
Wholesale Rate Base	\$1.8 B (DEC) 3Q 2019 \$3.2 B (DEP) 3Q 2019		\$1.9 B [3]	\$555 M	\$0.6 B (trans. only)	\$0
Allowed ROE	9.9% (DEC & DEP)	9.5% (DEC & DEP)	10.50% [6]	10.50%	9.84% - Dist 11.38% - Trans	9.725%
Allowed Equity	52.0% (DEC & DEP)	53.0% (DEC & DEP)	41.54% [7]	44.44% [8]	50.8%	49.3%
Effective Date of Most Recent Rates	8/1/18 (DEC) 3/16/18 (DEP)	6/1/19 (DEC & DEP)	1/1/20	5/24/04	Distr: 1/2/19 Trans 6/1/19 ESP: 1/2/19	4/13/18
Fuel Clause Updated	Annually (DEC & DEP)	Annually (DEC & DEP)	Annually	Quarterly	Annually for Non-Shoppers	Monthly
Environmental Clause Updated	N/A	N/A	Annually	Semi-Annually	Quarterly	Monthly

(1) DEC SC and DEP SC rate base and allowed ROE as of June 2019. The Public Service Commission of South Carolina issued orders in the DEC SC and DEP SC rate cases on May 21, 2019. DEC and DEP filed notices of appeal on November 15, 2019.
(2) DEC NC's rate base as of August 2018. DEP NC's rate base as of March 2018.
(3) Florida's thirteen-month average as of November 2019. Retail rate base includes amounts recovered in base rates of \$13.0B and amounts recovered in trackers of \$0.5B.
(4) As of November 30, 2019; includes amounts being recovered in base rates of \$3.7B, amounts being recovered in environmental trackers of \$1.0B, and amounts being recovered in IGCC trackers of \$2.1B and other trackers of \$0.3B
(5) Kentucky allows recovery on total capitalization instead of rate base
(6) Represents the mid-point of an authorized range from 9.5% to 11.5%
(7) Florida's capital structure includes accumulated deferred income taxes (ADIT), customer deposits and investment tax credits (ITC) and is as of Nov. 30, 2019. Excluding these items, the capital structure approximates 50% equity
(8) Indiana's capital structure includes ADIT. When ADIT is excluded, the capital structure approximates 53% equity

Current electric rate information by jurisdiction (continued)

General Rate Case Provisions

	North Carolina	South Carolina	Florida	Indiana	Ohio (Electric)	Kentucky (Electric)
Notice of Intent Required?	Yes	Yes	Yes	Yes [1]	Yes	Yes
Notice Period	30 Days	30 Days	60 Days	Varies	30 Days	30 Days
Test Year	Historical Adjusted for Known and Measureable Changes	Historical Adjusted for Known and Measureable Changes	Projected	Optional [2]	Partially Projected	Forecast Optional
Time Limitation Between Cases	No	12 months	No	15 Months	No	No
Rates Effective Subject to Refund	9 Months After Filing	6 Months After Filing [3]	8 Months After Filing	10 Months After Filing [4]	9 Months After Filing	6 Months After Filing [5]

(1) IURC recommended procedure. Not a statutory requirement
(2) Utilities may elect to a historical test period, a forward-looking test period, or a hybrid test year in the context of a general rate case
(3) If the South Carolina Commission fails to rule on a rate case filing within 6 months, the new rates can be implemented and are not subject to refund. There is a grace period here. The Company would have to notify the Commission that it planned to put rates in and the Commission would then have 10 additional days to issue an order
(4) The utility may implement interim rates, subject to refund, if the IURC has not rendered a decision within 10 months of filing (can be extended 60 days by IURC). The interim rates are not to exceed 50% of the original request
(5) The effective date is 7 months after filing for a forecasted test year

DUKE ENERGY.

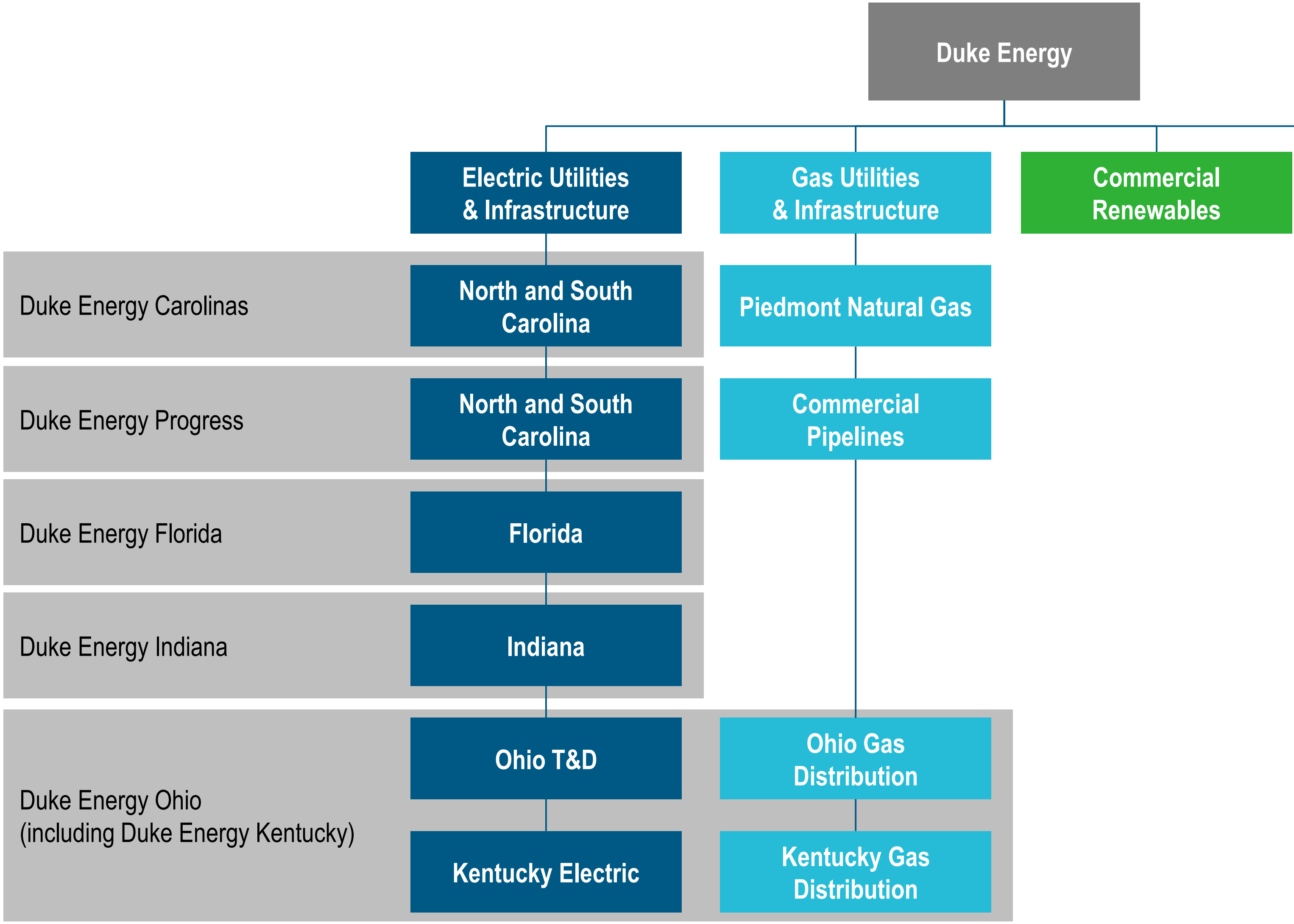
Current gas rate information by jurisdiction

	North Carolina	South Carolina	Tennessee	Ohio (Gas)	Kentucky (Gas)
Rate Base ($M)	$3.5 billion	$366 million	$349 million	$900 million(1)	$313 million (2)
Allowed ROE	9.7%	9.9%	10.2%	9.84%	9.7%
Allowed Equity	52%	55.35%	52.7%	53.3%	50.8%
Effective Date of Most Recent Rates	11/1/19	11/1/19 (3)	3/1/12	12/1/13	4/1/19
Significant Rider Mechanisms	Margin Decoupling Rider Integrity Management Rider Fuel Clause	Rate Stabilization Adj. Weather Normalization Adj. Fuel Clause	Weather Normalization Adj. Integrity Management Rider Fuel Clause	AMRP SmartGrid(4) Fuel Clause Capital Expenditure(5)	Weather Normalization Adj. Fuel Clause

(1) Excludes all rate base related to capital recovery that is being tracked (e.g., AMRP and AU after 3/31/2012)
(2) Kentucky allows recovery on total capitalization instead of rate base
(3) Rates refreshed annually under the South Carolina Rate Stabilization Act (RSA)
(4) The Ohio Commission temporarily suspended DEO's Gas SmartGrid Rider pending an audit.
(5) The Company has a pending application to implement a capital expenditure rider (Rider CEP) that will recover certain capital-related costs for incremental investment in most gas utility plant since the most recent base rate case approved in 2012.

Segment overviews

Duke Energy business segment structure



Duke Energy – a large scale, highly regulated energy infrastructure company

DUKE ENERGY.

HEADQUARTERED IN CHARLOTTE, NC

DUK
LISTED
NYSE

A FORTUNE 150 COMPANY

$71 B
MARKET CAP
(AS OF 2/11/2020)

$159 B
TOTAL ASSETS
(AS OF 12/31/2019)

29 K
EMPLOYEES
(AS OF 12/31/2019)

53 GWs
TOTAL GENERATING CAPACITY (AS OF 12/31/2019)

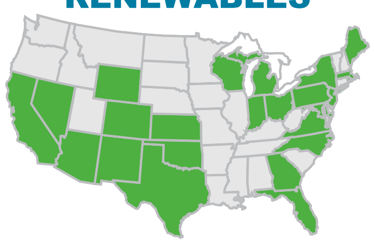
ELECTRIC UTILITIES & INFRASTRUCTURE

- Operating in six constructive jurisdictions, with attractive allowed ROEs, serving 7.8 million retail customers
- Customer rates below the national average(1)
- Balanced generation portfolio that has reduced its carbon emissions by 39% since 2005
- Industry-leading safety performance, as recognized by EEI

GAS UTILITIES & INFRASTRUCTURE

- Five state LDCs serving 1.6 million customers
- Strong earnings trajectory driven by customer growth, system integrity improvements, and continued expansion of natural gas infrastructure
- Significant investments in midstream natural gas pipelines and storage facilities

COMMERCIAL RENEWABLES



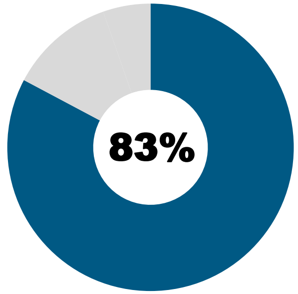
- Invested ~$5 billion over the past 10 years
- Approximately 4 GWs of wind and solar in operation
- Long-term Power Purchase Agreements with creditworthy counterparties

(1) Source: EEI Typical Bills and Average Rates Report, Winter 2019

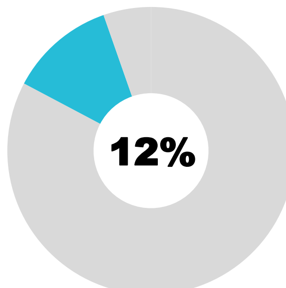
Complementary businesses with strong growth opportunities

Segment	2020 ADJUSTED EPS CONTRIBUTION[1]	2020-2024 CAPEX
ELECTRIC UTILITIES & INFRASTRUCTURE	83%	$45.6 B
GAS UTILITIES & INFRASTRUCTURE	12%	$7.3 B
COMMERCIAL RENEWABLES	5%	$2.2 B[3]

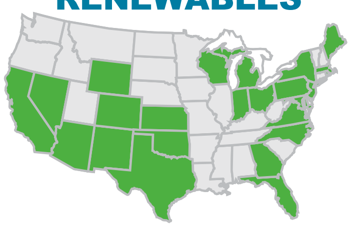
ELECTRIC UTILITIES & INFRASTRUCTURE

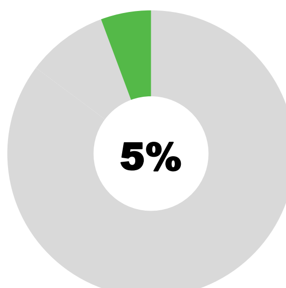


GAS UTILITIES & INFRASTRUCTURE



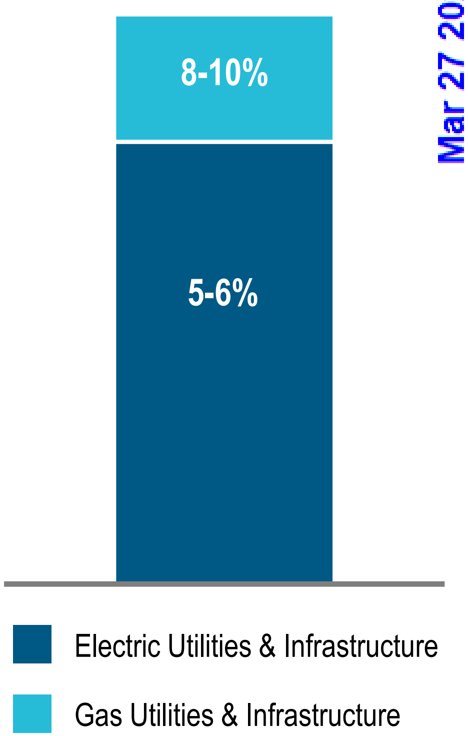
COMMERCIAL RENEWABLES





2020 – 2024 ADJUSTED EPS CAGR[2]

Consolidated 4-6%



(1) *Based upon the midpoint of the 2020 adjusted EPS guidance range of $5.05-$5.45 per share; excludes the impact of Other*
(2) *CAGR off of the components of the midpoint of the 2019 EPS guidance range of $4.80-$5.20 per share; consolidated growth rate includes the impact of Commercial Renewables (approximately flat growth) and Other*
(3) *Net of tax equity financing*

EIGHT UTILITIES IN HIGH-QUALITY REGIONS OF THE U.S.

CAROLINAS

Duke Energy Carolinas (NC/SC)

Duke Energy Progress (NC/SC)

FLORIDA

Duke Energy Florida

MIDWEST

Duke Energy Indiana

Duke Energy Ohio / Kentucky

COMPETITIVE CUSTOMER RATES[1]

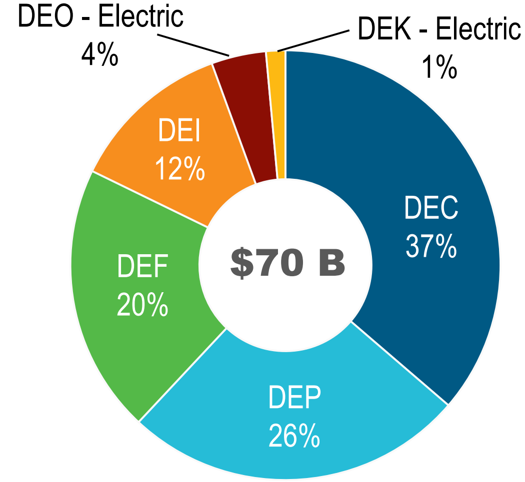
RESIDENTIAL

COMMERCIAL

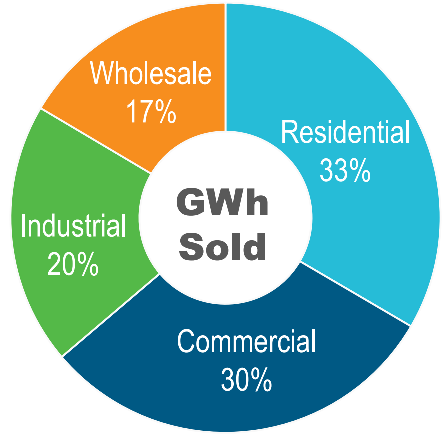
INDUSTRIAL

(1) *Typical bill rates (¢/kWh) in effect as of July 1, 2019. Vertically integrated utilities only. Source: EEI Typical Bills and Avg. Rates Report, Winter 2019*

REGULATED ELECTRIC 2019 EARNINGS BASE

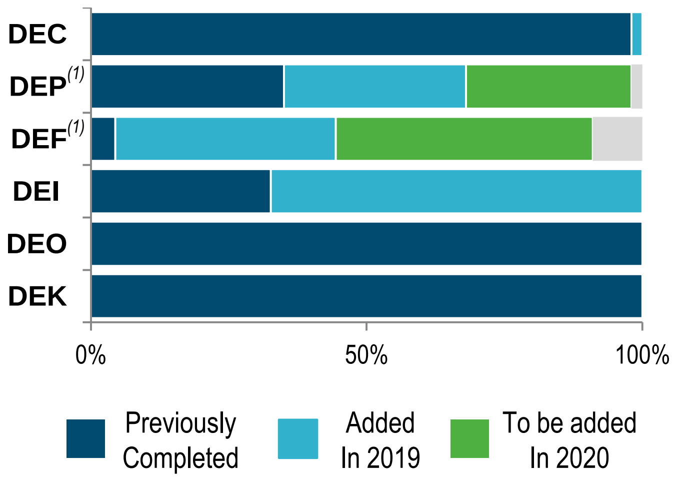


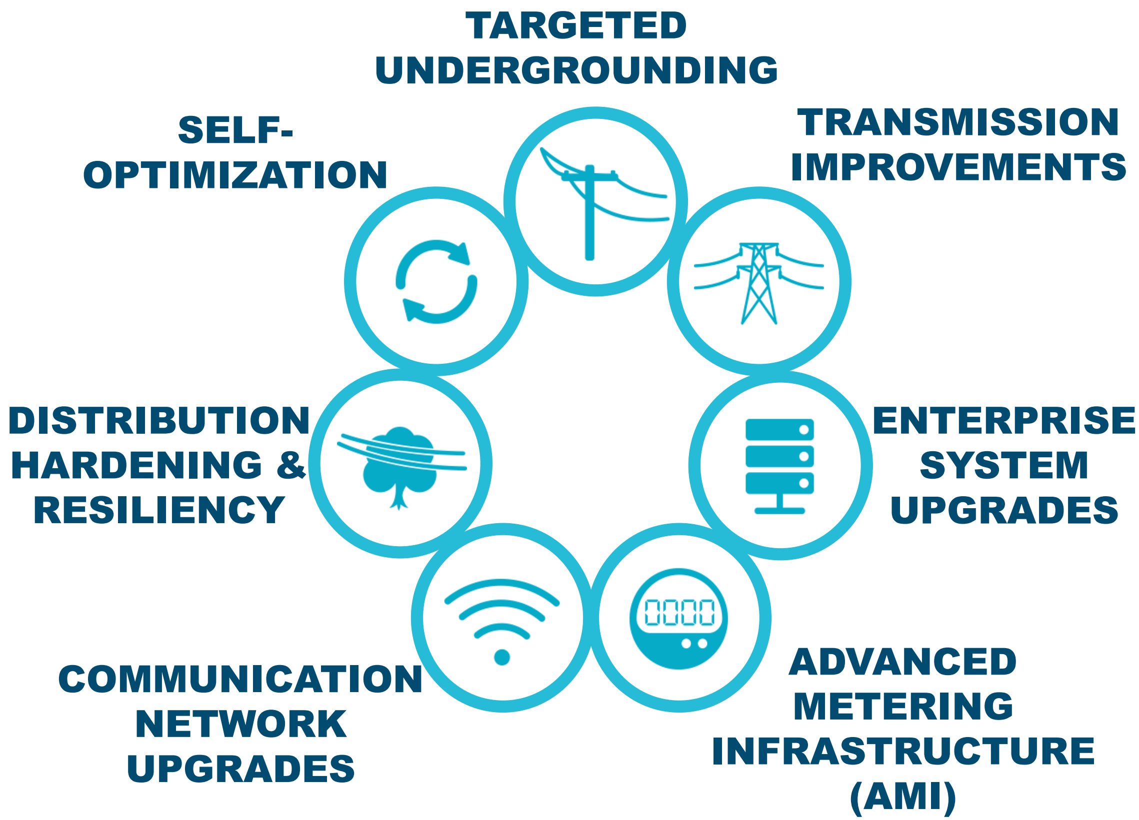
BALANCED CUSTOMER MIX



Grid improvement programs overview

AMI DEPLOYMENT





PRIMARY RECOVERY MECHANISMS

Carolinas	Base rate cases
Florida	Multi-year base rate plan
Indiana	TDSIC rider
Ohio	DCI and BTR riders
Kentucky	Base rate cases

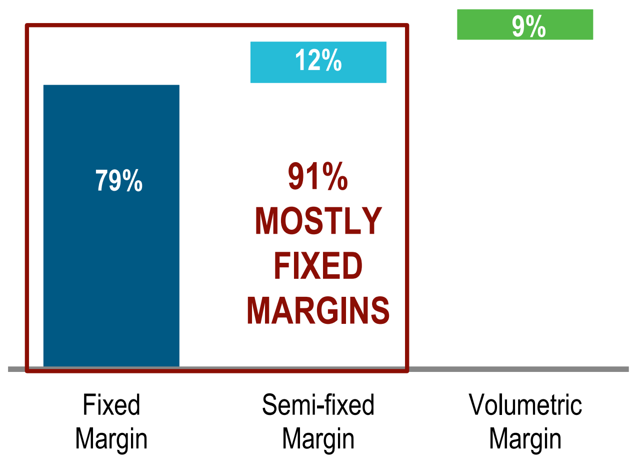
CUSTOMER BENEFITS

- Increased reliability
- Provide information customers value
- Enable distributed generation
- Improve cyber and physical security

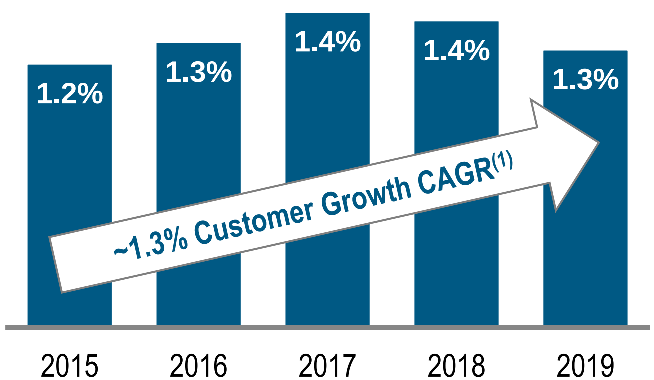
(1) Remaining amounts expected to be completed in Q1 2021

Gas utilities & infrastructure

GAS UTILITIES WITH LOW VOLUMETRIC EXPOSURE DUE TO **MOSTLY FIXED MARGINS…**



…WITH EARNINGS DRIVEN BY **INVESTMENT AND STRONG RESIDENTIAL CUSTOMER GROWTH**



(1) *Piedmont CAGR: 1.6%, Midwest LDC CAGR 0.8%*

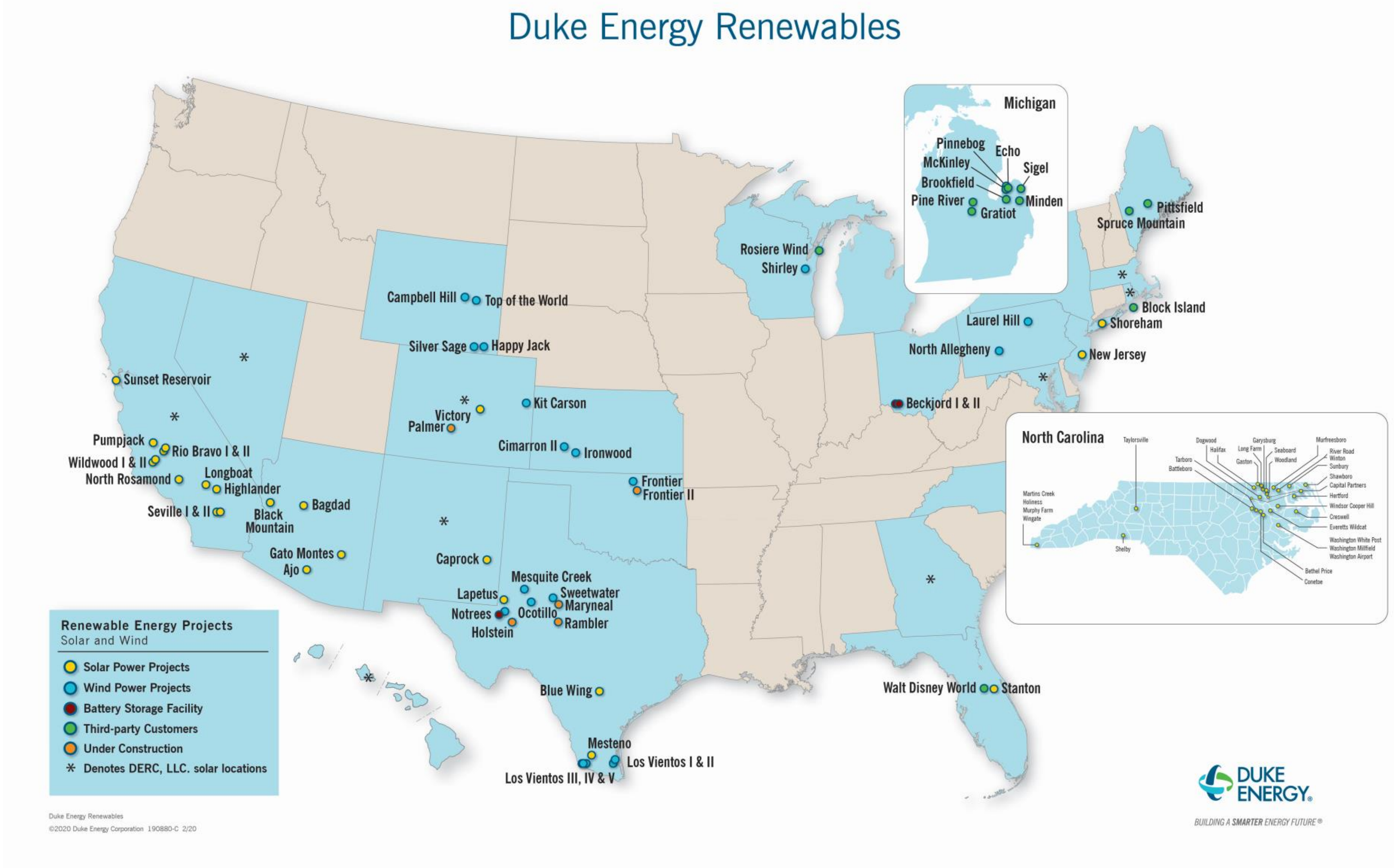
MARGIN STABILIZING MECHANISMS

1. Purchased Gas Adjustment	All States
2. Uncollectible Recovery	All States
3. Integrity Management Rider ("IMR")	North Carolina and Tennessee
4. Margin Decoupling	North Carolina
5. Weather Normalization	South Carolina, Tennessee and Kentucky
6. Rate Stabilization Act	South Carolina
7. Accelerated Main Replacement Program Rider	Ohio
8. Advanced Utility Rider	Ohio
9. Manufactured Gas Rider	Ohio

Commercial Renewables asset locations

A full list of generation facilities can be found at:

https://www.duke-energy.com//_/media/pdfs/our-company/investors/duke-energy-generation-portfolio.pdf



Upcoming events & other

Upcoming events

Event	Date
1Q 2020 earnings call (tentative)	May 1, 2020
May 2020 ESG Investor day (tentative)	Mid to late May 2020
2Q 2020 earnings call (tentative)	August 6, 2020
3Q 2020 earnings call (tentative)	November 5, 2020

Investor relations contact information

BRYAN BUCKLER, VICE PRESIDENT INVESTOR RELATIONS

- Bryan.Buckler@duke-energy.com
- (704) 382-2640

CINDY LEE, DIRECTOR INVESTOR RELATIONS

- Cynthia.Lee@duke-energy.com
- (980) 373-4077

ABBY MOTSINGER, MANAGER INVESTOR RELATIONS

- Abby.Motsinger@duke-energy.com
- (704) 382-7624

Safe harbor statement

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions and can often be identified by terms and phrases that include "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," "target," "guidance," "outlook" or other similar terminology. Various factors may cause actual results to be materially different than the suggested outcomes within forward-looking statements; accordingly, there is no assurance that such results will be realized. These factors include, but are not limited to: State, federal and foreign legislative and regulatory initiatives, including costs of compliance with existing and future environmental requirements, including those related to climate change, as well as rulings that affect cost and investment recovery or have an impact on rate structures or market prices; The extent and timing of costs and liabilities to comply with federal and state laws, regulations and legal requirements related to coal ash remediation, including amounts for required closure of certain ash impoundments, are uncertain and difficult to estimate; The ability to recover eligible costs, including amounts associated with coal ash impoundment retirement obligations and costs related to significant weather events, and to earn an adequate return on investment through rate case proceedings and the regulatory process; The costs of decommissioning nuclear facilities could prove to be more extensive than amounts estimated and all costs may not be fully recoverable through the regulatory process; Costs and effects of legal and administrative proceedings, settlements, investigations and claims; Industrial, commercial and residential growth or decline in service territories or customer bases resulting from sustained downturns of the economy and the economic health of our service territories or variations in customer usage patterns, including energy efficiency efforts and use of alternative energy sources, such as self-generation and distributed generation technologies; Federal and state regulations, laws and other efforts designed to promote and expand the use of energy efficiency measures and distributed generation technologies, such as private solar and battery storage, in Duke Energy service territories could result in customers leaving the electric distribution system, excess generation resources as well as stranded costs; Advancements in technology; Additional competition in electric and natural gas markets and continued industry consolidation; The influence of weather and other natural phenomena on operations, including the economic, operational and other effects of severe storms, hurricanes, droughts, earthquakes and tornadoes, including extreme weather associated with climate change; The ability to successfully operate electric generating facilities and deliver electricity to customers including direct or indirect effects to the company resulting from an incident that affects the U.S. electric grid or generating resources; The ability to obtain the necessary permits and approvals and to complete necessary or desirable pipeline expansion or infrastructure projects in our natural gas business; Operational interruptions to our natural gas distribution and transmission activities; The availability of adequate interstate pipeline transportation capacity and natural gas supply; The impact on facilities and business from a terrorist attack, cybersecurity threats, data security breaches, operational accidents, information technology failures or other catastrophic events, such as fires, explosions, pandemic health events or other similar occurrences; The inherent risks associated with the operation of nuclear facilities, including environmental, health, safety, regulatory and financial risks, including the financial stability of third-party service providers; The timing and extent of changes in commodity prices and interest rates and the ability to recover such costs through the regulatory process, where appropriate, and their impact on liquidity positions and the value of underlying assets; The results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings, interest rate fluctuations, compliance with debt covenants and conditions and general market and economic conditions; Credit ratings of the Duke Energy Registrants may be different from what is expected; Declines in the market prices of equity and fixed-income securities and resultant cash funding requirements for defined benefit pension plans, other post-retirement benefit plans and nuclear decommissioning trust funds; Construction and development risks associated with the completion of the Duke Energy Registrants' capital investment projects, including risks related to financing, obtaining and complying with terms of permits, meeting construction budgets and schedules and satisfying operating and environmental performance standards, as well as the ability to recover costs from customers in a timely manner, or at all; Changes in rules for regional transmission organizations, including changes in rate designs and new and evolving capacity markets, and risks related to obligations created by the default of other participants; The ability to control operation and maintenance costs; The level of creditworthiness of counterparties to transactions; The ability to obtain adequate insurance at acceptable costs; Employee workforce factors, including the potential inability to attract and retain key personnel; The ability of subsidiaries to pay dividends or distributions to Duke Energy Corporation holding company (the Parent); The performance of projects undertaken by our nonregulated businesses and the success of efforts to invest in and develop new opportunities; The effect of accounting pronouncements issued periodically by accounting standard-setting bodies; The impact of U.S. tax legislation to our financial condition, results of operations or cash flows and our credit ratings; The impacts from potential impairments of goodwill or equity method investment carrying values; and The ability to implement our business strategy, including enhancing existing technology systems.

Additional risks and uncertainties are identified and discussed in the Duke Energy Registrants' reports filed with the SEC and available at the SEC's website at sec.gov. In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than described. Forward-looking statements speak only as of the date they are made and the Duke Energy Registrants expressly disclaim an obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

DUKE ENERGY®

BUILDING A **SMARTER** ENERGY FUTURE®

For additional information on Duke Energy,
please visit: duke-energy.com/investors

Duke Energy Corporation
Non-GAAP Reconciliations
Fourth Quarter Earnings Review & Business Update
February 13, 2020

Adjusted Earnings per Share (EPS)

The materials for Duke Energy Corporation's (Duke Energy) Fourth Quarter Earnings Review and Business Update on February 13, 2020, include a discussion of adjusted EPS for the year-to-date periods ended December 31, 2019, 2018 and 2017.

The non-GAAP financial measure, adjusted EPS, represents basic and diluted EPS from continuing operations available to Duke Energy Corporation common stockholders, adjusted for the per share impact of special items. As discussed below, special items represent certain charges and credits, which management believes are not indicative of Duke Energy's ongoing performance.

Management believes the presentation of adjusted EPS provides useful information to investors, as it provides them with an additional relevant comparison of Duke Energy's performance across periods. Management uses this non-GAAP financial measure for planning and forecasting and for reporting financial results to the Duke Energy Board of Directors (Board of Directors), employees, stockholders, analysts and investors. Adjusted EPS is also used as a basis for employee incentive bonuses. The most directly comparable GAAP measure for adjusted EPS is reported basic and diluted EPS available to Duke Energy Corporation common stockholders. Reconciliations of adjusted EPS for the year-to-date periods ended December 31, 2019, 2018 and 2017, to the most directly comparable GAAP measures are included herein.

Special items for the year-to-date periods ended December 31, 2019, 2018 and 2017, include the following items, which management believes do not reflect ongoing costs:

- Impairment Charges in 2019 represents a reduction of a prior-year impairment at Citrus County CC and an other-than-temporary-impairment on the remaining investment in Constitution Pipeline Company, LLC. For 2018, it represents an impairment at Citrus County CC, a goodwill impairment at Commercial Renewables and an other-than-temporary impairment of an investment in Constitution Pipeline Company, LLC. For 2017, the charges represent goodwill and other-than-temporary asset impairments at Commercial Renewables. For 2017, it represents charges related to the Levy nuclear project in Florida and the Mayo Zero Liquid Discharge and Sutton combustion turbine projects in North Carolina.
- Costs to Achieve Mergers represents charges that resulted from strategic acquisitions.
- Regulatory and Legislative Impacts in 2018 represents charges related to Duke Energy Progress and Duke Energy Carolinas North Carolina rate case orders and the repeal of the South Carolina Base Load Review Act.
- Sale of Retired Plant represents the loss associated with selling Beckjord, a nonregulated generating facility in Ohio.
- Impacts of the Tax Act represents amounts recognized related to the Tax Act.
- Severance Charges relate to companywide initiatives, excluding merger integration, to standardize processes and systems, leverage technology and workforce optimization.

Adjusted EPS Guidance

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 13, 2020, include a reference to the forecasted 2020 adjusted EPS guidance range of $5.05 to $5.45 per share and the midpoint of forecasted 2020 adjusted EPS guidance range of $5.25. The materials also reference the long-term range of annual growth of 4% - 6% through 2024 off the original midpoint of 2019 adjusted EPS guidance range of $5.00. The forecasted adjusted EPS is a non-GAAP financial measure as it represents basic EPS from continuing operations available to Duke Energy Corporation common stockholders, adjusted for the per share impact of special items (as discussed above under Adjusted EPS). Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items for future periods, such as legal settlements, the impact of regulatory orders or asset impairments.

For the years ended December 31, 2018 and 2019, Basic EPS Available to Duke Energy Corporation common stockholders and Diluted EPS Available to Duke Energy Corporation common stockholders were equal. Beginning in 2020, Duke Energy will use adjusted basic EPS as the financial measure to evaluate management performance. Adjusted basic EPS will represent Basic EPS Available to Duke Energy Corporation common stockholders (GAAP reported Basic EPS), adjusted for the per-share impact of special items.

Adjusted Segment Income and Adjusted Other Net Loss

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 13, 2020, include a discussion of adjusted segment income and adjusted other net loss for the year-to-date periods ended December 31, 2019 and 2018, and a discussion of 2019 and 2020 forecasted adjusted segment income and forecasted adjusted other net loss.

Adjusted segment income and adjusted other net loss are non-GAAP financial measures, as they represent reported segment income and other net loss adjusted for special items (as discussed above under Adjusted EPS). Management believes the presentation of adjusted segment income and adjusted other net expense provides useful information to investors, as it provides an additional relevant comparison of a segment's or Other's performance across periods. When a per share impact is provided for a segment income driver, the after-tax driver is derived using the pretax amount of the item less income taxes based on the segment statutory tax rate of 24% for Electric Utilities and Infrastructure, 23% for Gas Utilities and Infrastructure and Other, or an effective tax rate for Commercial Renewables. The after-tax earnings drivers are divided by the Duke Energy weighted average shares outstanding for the period. The most directly comparable GAAP measures for adjusted segment income and adjusted other net loss are reported segment income and other net loss, which represents segment income and other net loss from continuing operations, including any special items. A reconciliation of adjusted segment income and adjusted other net loss for the year-to-date periods ended December 31, 2019 and 2018, to the most directly comparable GAAP measures is included herein. Due to the forward-looking nature of any forecasted adjusted segment income and forecasted other net loss and any related growth rates for future periods, information to reconcile these non-GAAP financial measures to the most directly comparable GAAP financial measures are not available at this time, as the company is unable to forecast all special items, as discussed above under Adjusted EPS guidance.

Effective Tax Rate Including Impacts of Noncontrolling Interests and Preferred Dividends and Excluding Special Items

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 13, 2020, include a discussion of the effective tax rate including impacts of noncontrolling interests and preferred dividends and excluding special items for the year-to-date periods ended December 31, 2019. The materials also include a discussion of the 2019 and 2020 forecasted effective tax rate including impacts of noncontrolling interests and preferred dividends and excluding special items. Effective tax rate including impacts of noncontrolling interests and preferred dividends and excluding special items is a non-GAAP financial measure as the rate is calculated using pretax income and income tax expense, both adjusted for the impact of special items, noncontrolling interests and preferred dividends. The most directly comparable GAAP measure is reported effective tax rate, which includes the impact of special items and excludes the impacts of noncontrolling interests and preferred dividends. A reconciliation of this non-GAAP financial measure for the year-to-date periods ended December 31, 2019, to the most directly comparable GAAP measure is included herein. Due to the forward-looking nature of the forecasted effective tax rates including impacts of noncontrolling interests and preferred dividends and excluding special items, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted EPS Guidance.

Available Liquidity

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 13, 2020, include a discussion of Duke Energy's available liquidity balance. The available liquidity balance presented is a non-GAAP financial measure as it represents cash and cash equivalents, excluding certain amounts held in foreign jurisdictions and cash otherwise unavailable for operations, and remaining availability under Duke Energy's available credit facilities, including the master credit facility. The most directly comparable GAAP financial measure for available liquidity is cash and cash equivalents. A reconciliation of available liquidity as of December 31, 2019, to the most directly comparable GAAP measure is included herein.

Non-Rider Recoverable O&M

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 13, 2020, include a discussion of Duke Energy's non-rider recoverable operating, maintenance and other expenses (O&M) for the year-to-date periods ended December 31, 2019, 2018, 2017 and 2016 as well as the forecasted year-to-date period ended December 31, 2020. Non-rider recoverable O&M expenses are non-GAAP financial measures, as they represent reported O&M expenses adjusted for special items and expenses recovered through riders. The most directly comparable GAAP financial measure for non-rider recoverable O&M expenses is reported operating, maintenance and other expenses. A reconciliation of non-rider recoverable O&M expenses for the year-to-date periods ended December 31, 2019, 2018, 2017, and 2016, as well as the forecasted year-to-date period ended December 31, 2020, to the most directly comparable GAAP measure are included here-in. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted ;EPS Guidance; However, projected rider recoverable O&M costs have been forecasted for the year ended December 31, 2020 and are presented in the reconciliation herein.

Dividend Payout Ratio

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 13, 2020, include a discussion of Duke Energy's forecasted dividend payout ratio of 65% - 75% based upon adjusted EPS. This payout ratio is a non-GAAP financial measure as it is based upon forecasted basic EPS from continuing operations available to Duke Energy Corporation stockholders, adjusted for the per-share impact of special items, as discussed above under Adjusted EPS. The most directly comparable GAAP measure for adjusted EPS is reported basic EPS available to Duke Energy Corporation common stockholders. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted EPS Guidance.

The materials also reference the 2019 actual dividend payout ratio of 74%. This payout ratio is a non-GAAP financial measure as it is the annualized Q4 2019 dividend divided by the 2019 adjusted EPS (as discussed above under Adjusted EPS Guidance). On an annualized basis, the Q4 2019 dividend of $0.9540 is equal to $3.78, which creates an annual dividend payout ratio of 74% when compared to 2019 adjusted EPS.

Adjusted Book Return on Equity (ROE)

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 13, 2020 include a reference to the historical and projected adjusted book return on equity (ROE) ratio. This ratio is a non-GAAP financial measure. The numerator represents Net Income, adjusted for the impact of special items (as discussed above under Adjusted EPS). The denominator is average Total Common Stockholder's Equity, reduced for Goodwill. A reconciliation of the components of adjusted ROE to the most directly comparable GAAP measures is included here-in. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted EPS Guidance.

Funds From Operations ("FFO") Ratios

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 13, 2020 include a reference to historical and expected FFO to Total Debt ratios. These ratios reflect non-GAAP financial measures. The numerator of the FFO to Total Debt ratio is calculated principally by using net cash provided by operating activities on a GAAP basis, adjusted for changes in working capital, ARO spend, depreciation and amortization of operating leases and reduced for capitalized interest (including any AFUDC interest) and AMT refunds. The denominator for the FFO to Total Debt ratio is calculated principally by using the balance of long-term debt (excluding purchase accounting adjustments and long-term debt associated with the CR3 Securitization), including current maturities, imputed operating lease liabilities, plus notes payable, commercial paper outstanding, underfunded pension, guarantees on joint-venture debt, and adjustments to hybrid debt and preferred equity issuances based on how credit rating agencies view the instruments. The calculation of FFO to Total Debt ratio for the year ended December 31, 2019 is included here-in. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted EPS Guidance.

Holdco Debt Percentage

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 13, 2020 include a reference to a historical and projected Holdco debt percentage. This percentage reflects a non-GAAP financial measure. The numerator of the Holdco debt percentage is the balance of Duke Energy Corporate debt, Progress Energy, Inc. debt, PremierNotes and the Commercial Paper attributed to the Holding Company. The denominator for the percentage is the balance of long-term debt (excluding purchase accounting adjustments and long-term debt associated with the CR3 Securitization), including current maturities, imputed operating lease liabilities, plus notes payable and commercial paper outstanding

Business Mix Percentage

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 13, 2020, reference each segment's 2020 projected adjusted segment income as a percentage of the total projected 2020 adjusted net income (i.e. business mix), excluding the impact of Other. Duke Energy's segments are comprised of Electric Utilities and Infrastructure, Gas Utilities and Infrastructure and Commercial Renewables.

Adjusted segment income is a non-GAAP financial measure, as it represents reported segment income adjusted for special items as discussed above. Due to the forward-looking nature of any forecasted adjusted segment income, information to reconcile this non-GAAP financial measure to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items (as discussed above under Adjusted EPS Guidance).

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Year Ended December 31, 2019
(Dollars in millions, except per-share amounts)

	Reported Earnings	Special Items: Impairment Charges	Special Items: Discontinued Operations	Total Adjustments	Adjusted Earnings
SEGMENT INCOME					
Electric Utilities and Infrastructure	**$ 3,536**	$ (27) **A**	$ —	$ (27)	$ 3,509
Gas Utilities and Infrastructure	**432**	19 **B**	—	19	451
Commercial Renewables	**198**	—	—	—	198
Total Reportable Segment Income	**4,166**	**(8)**	**—**	**(8)**	**4,158**
Other	**(452)**		—	—	(452)
Discontinued Operations	**(7)**	—	7 **C**	7	—
Net Income Available to Duke Energy Corporation Common Stockholders	**$ 3,707**	**$ (8)**	**$ 7**	**$ (1)**	**$ 3,706**
EPS AVAILABLE TO DUKE ENERGY CORPORATION COMMON STOCKHOLDERS, DILUTED	**$ 5.06**	**$ (0.01)**	**$ 0.01**	**$ —**	**$ 5.06**

Note: Earnings Per Share amounts are adjusted for accumulated but not yet declared dividends for Series B Preferred Stock of $(0.02).

A – Net of $9 million tax expense. $36 million reduction of a prior year impairment recorded within Impairment charges for the Citrus County CC project on Duke Energy Florida's Consolidated Statements of Operations.

B – Net of $6 million tax benefit. $25 million included within Other Income and Expenses on the Consolidated Statements of Operations, related to the other-than-temporary-impairment of the remaining investment in Constitution Pipeline Company, LLC.

C – Recorded in (Loss) Income from Discontinued Operations, net of tax on the Consolidated Statements of Operations.

Weighted Average Shares, Diluted (reported and adjusted) – 729 million

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Year Ended December 31, 2018
(Dollars in millions, except per-share amounts)

		Special Items								
	Reported Earnings	Costs to Achieve Piedmont Merger	Regulatory and Legislative Impacts	Sale of Retired Plant	Impairment Charges	Impacts of the Tax Act	Severance	Discontinued Operations	Total Adjustments	Adjusted Earnings
SEGMENT INCOME										
Electric Utilities and Infrastructure	**$ 3,058**	$ —	$ 202 **B**	$ —	$ 46 **D**	$ 24	$ —	$ —	$ 272	$ 3,330
Gas Utilities and Infrastructure	**274**	—	—	—	42 **E**	1	—	—	43	317
Commercial Renewables	**9**	—	—	—	91 **F**	(3)	—	—	88	97
Total Reportable Segment Income	**3,341**	**—**	**202**	**—**	**179**	**22**	**—**	**—**	**403**	**3,744**
Other	**(694)**	65 **A**	—	82 **C**	—	(2)	144 **H**	—	289	(405)
Discontinued Operations	**19**	—	—	—	—	—	—	(19) **I**	(19)	—
Net Income Attributable to Duke Energy Corporation	**$ 2,666**	**$ 65**	**$ 202**	**$ 82**	**$ 179**	**$ 20 G**	**$ 144**	**$ (19)**	**$ 673**	**$ 3,339**
EPS ATTRIBUTABLE TO DUKE ENERGY CORPORATION, DILUTED	**$ 3.76**	**$ 0.09**	**$ 0.29**	**$ 0.12**	**$ 0.25**	**$ 0.03**	**$ 0.21**	**$ (0.03)**	**$ 0.96**	**$ 4.72**

A – Net of $19 million tax benefit. $84 million recorded within Operating Expenses on the Consolidated Statements of Operations.

B – Net of $16 million tax benefit at Duke Energy Progress and $47 million tax benefit at Duke Energy Carolinas, related to the North Carolina rate case orders and the repeal of the South Carolina Base Load Review Act.

- On the Duke Energy Progress' Consolidated Statements of Operations, $32 million is recorded within Impairment charges, $31 million within Operations, maintenance and other, $6 million within Interest Expense and $(1) million within Depreciation and amortization.
- On the Duke Energy Carolinas' Consolidated Statements of Operations, $188 million is recorded within Impairment charges, $8 million within Operations, maintenance and other, and $1 million within Depreciation and amortization.

C – Net of $25 million tax benefit. $107 million recorded within Gains (Losses) on Sales of Other Assets and Other, net on the Consolidated Statements of Operations. Sale of retired plant represents the loss associated with selling Beckjord, a nonregulated generating facility in Ohio.

D – Net of $14 million tax benefit. $60 million recorded within Impairment charges for the Citrus County CC project on Duke Energy Florida's Consolidated Statements of Operations.

E – Net of $13 million tax benefit. $55 million recorded within Other Income and Expenses on the Consolidated Statements of Operations, related to the other-than-temporary-impairment of the investment in Constitution Pipeline Company, LLC.

F – Net of $2 million Noncontrolling Interests. $93 million goodwill impairment recorded within Impairment charges on the Consolidated Statement of Operations.

G – $20 million true up of prior year Tax Act estimates within Income Tax Expense from Continuing Operations on the Consolidated Statements of Operations.

H – Net of $43 million tax benefit. $187 million recorded with Operations, maintenance and other on the Consolidated Statements of Operations.

I – Recorded in (Loss) Income from Discontinued Operations, net of tax on the Consolidated Statements of Operations.

Weighted Average Shares, Diluted (reported and adjusted) – 708 million

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Twelve Months Ended December 31, 2017
(Dollars in millions, except per-share amounts)

		Special Items						
	Reported Earnings	Costs to Achieve Piedmont Merger	Regulatory Settlements	Commercial Renewables Impairments	Impacts of the Tax Act	Discontinued Operations	Total Adjustments	Adjusted Earnings
SEGMENT INCOME								
Electric Utilities and Infrastructure	$ 3,210	$ —	$ 98 **B**	$ —	$ (231)	$ —	$ (133)	$ 3,077
Gas Utilities and Infrastructure	319	—	—	—	(26) **D**	—	(26)	293
Commercial Renewables	441	—	—	74 **C**	(442)	—	(368)	73
Total Reportable Segment Income	**3,970**	**—**	**98**	**74**	**(699)**	**—**	**(527)**	**3,443**
Other	(905)	64 **A**	—	—	597	—	661	(244)
Discontinued Operations	(6)	—	—	—	—	6 **E**	6	—
Net Income Attributable to Duke Energy Corporation	**$ 3,059**	**$ 64**	**$ 98**	**$ 74**	**$ (102) D**	**$ 6**	**$ 140**	**$ 3,199**
EPS ATTRIBUTABLE TO DUKE ENERGY CORP, DILUTED	**$ 4.36**	**$ 0.09**	**$ 0.14**	**$ 0.11**	**$ (0.14)**	**$ 0.01**	**$ 0.21**	**$ 4.57**

A - Net of $39 million tax benefit. $102 million recorded within Operating Expenses and $1 million recorded within Interest Expense on the Consolidated Statements of Operations.

B - Net of $60 million tax benefit. $154 million recorded within Impairment charges and $4 million recorded within Other Income and Expenses on the Consolidated Statements of Operations.

C - Net of $28 million tax benefit. $92 million recorded within Impairment charges and $10 million recorded within Other Income and Expenses on the Consolidated Statements of Operations.

D - $118 million benefit recorded with Income Tax Expense from Continuing Operations, offset by $16 million expense recorded within Gas Utilities and Infrastructure's Equity in Earnings of Unconsolidated Affiliates on the Consolidated Statements of Operations.

E - Recorded in Income (Loss) from Discontinued Operations, net of tax on the Consolidated Statements of Operations.

Weighted Average Shares, Diluted (reported and adjusted) - 700 million

DUKE ENERGY CORPORATION
EFFECTIVE TAX RECONCILIATION
December 2019
(Dollars in millions)

	Three Months Ended December 31, 2019		Year Ended December 31, 2019	
	Balance	Effective Tax Rate	Balance	Effective Tax Rate
Reported Income From Continuing Operations Before Income Taxes	$ 709		$ 4,097	
Impairment Charges	14		(11)	
Noncontrolling Interests	67		177	
Preferred Dividends	(14)		(41)	
Pretax Income Including Noncontrolling Interests and Preferred Dividends and Excluding Special Items	$ 776		$ 4,222	
Reported Income Tax Expense From Continuing Operations	$ 95	13.4%	$ 519	12.7%
Impairment Charges	3		(3)	
Tax Expense Including Noncontrolling Interests and Preferred Dividends and Excluding Special Items	$ 98	12.6%	$ 516	12.2%

	Three Months Ended December 31, 2018		Year Ended December 31, 2018	
	Balance	Effective Tax Rate	Balance	Effective Tax Rate
Reported Income From Continuing Operations Before Income Taxes	$ 433		$ 3,073	
Costs to Achieve Piedmont Merger	31		84	
Regulatory and Legislative Impacts	—		265	
Sale of Retired Plant	—		107	
Impairment Charges	60		206	
Severance	187		187	
Noncontrolling Interests	10		22	
Pretax Income Including Noncontrolling Interests and Excluding Special Items	$ 721		$ 3,944	
Reported Income Tax (Benefit) Expense From Continuing Operations	$ (1)	(0.2)%	$ 448	14.6%
Costs to Achieve Piedmont Merger	7		19	
Regulatory and Legislative Impacts	—		63	
Sale of Retired Plant	—		25	
Impairment Charges	14		27	
Severance	43		43	
Impacts of the Tax Act	53		(20)	
Tax Expense Including Noncontrolling Interests and Excluding Special Items	$ 116	16.1 %	$ 605	15.3%

Duke Energy Corporation
Available Liquidity Reconciliation
As of December 31, 2019
(In millions)

Cash and Cash Equivalents	$ 311	
Less: Certain Amounts Held in Foreign Jurisdictions	(1)	
Less: Unavailable Domestic Cash	(33)	
	277	
Plus: Remaining Availability under Master Credit Facilities and other facilities	5,332	
Total Available Liquidity (a)	$ 5,609	approximately 5.6 billion

(a) The available liquidity balance presented is a non-GAAP financial measure as it represents Cash and cash equivalents, excluding certain amounts held in foreign jurisdictions and cash otherwise unavailable for operations, and remaining availability under Duke Energy's available credit facilities, including the master credit facility. The most directly comparable GAAP financial measure for available liquidity is Cash and cash equivalents.

Duke Energy Corporation
Operations, Maintenance and Other Expense
(In millions)

	Actual December 31, 2016	Actual December 31, 2017	Actual December 31, 2018	Actual December 31, 2019	Forecast December 31, 2020
Operation, maintenance and other[a]	**$6,223**	**$5,944**	**$6,463**	**$6,066**	**$6,061**
Adjustments:					
Costs to Achieve, Mergers[b]	(238)	(94)	(83)	–	–
Severance[b]	(92)	–	(187)	–	–
Regulatory settlement[b]	–	(5)	(40)	–	–
Reagents Recoverable[c]	(93)	(90)	(112)	(95)	(102)
Energy Efficiency Recoverable[c]	(417)	(485)	(446)	(415)	(424)
Other Deferrals and Recoverable[c]	(233)	(246)	(477)	(472)	(382)
Margin based O&M for Commercial Businesses	(185)	(94)	(113)	(95)	(202)
Short-term incentive payments (over)/under budget	(90)	(22)	(30)	(112)	–
Non-Rider Recoverable operation, maintenance and other	**$ 4,875**	**$ 4,908**	**$ 4,974**	**$ 4,878**	**$ 4,950**

(a) As reported in the Consolidated Statements of Operations.
(b) Presented as a special item for the purpose of calculating adjusted earnings and adjusted diluted earnings
(c) Primarily represents expenses to be deferred or recovered through rate riders.

DUKE ENERGY CORPORATION
ADJUSTED BOOK RETURN ON EQUITY (ROEs)
For the period ended December 31, 2019
dollars in millions

	Duke Energy Carolinas	Duke Energy Progress	Total Carolinas	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio Reportable Segments		Piedmont	
Reported Net Income 2019	$ 1,403	$ 805	$ 2,208	$ 693	$ 436	$ 244	(2)	$ 196	(4)
Special Items (1)	-	-	-	(27)	-	-		-	
Adjusted Net Income 2019	1,403	805	2,208	666	436	244		196	
2019									
Equity	12,811	9,246	22,057	6,788	4,575	3,687	(3)	2,381	(5)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	12,811	9,246	22,057	6,788	4,575	2,767		2,332	
2018									
Equity	11,683	8,441	20,124	6,095	4,339	3,449	(3)	2,047	(5)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	11,683	8,441	20,124	6,095	4,339	2,529		1,998	
Average Equity less Goodwill	12,247	8,844	21,091	6,442	4,457	2,648		2,165	
Adjusted Book ROEs			10.5%	10.3%	9.8%	9.2%		9.1%	

(1) Impacts of Citrus County CC, Net of Tax

(2) Net Income for 2019 equals Duke Energy Ohio reportable segments segment income

(3) Reconciliation of Duke Energy Ohio Equity to Equity of the reportable segments:

	2019	2018
Reported Equity for Duke Energy Ohio	3,683	3,445
Less: Non-Reg & Other	(4)	(4)
Duke Energy Ohio Reportable Segments Equity	3,687	3,449

(4) Piedmont Natural Gas Net Income excludes $6 million of income related to Investments in Gas Transmission Infrastructure

2019
202
(6)
196

(5) Reconciliation of Piedmont Natural Gas Equity to reported equity:

	2019	2018
Reported Equity for Piedmont Natural Gas	2,443	2,091
Less: Investments in Gas Transmission Infrastructure	62	44
Piedmont Natural Gas Adjusted Equity	2,381	2,047

DUKE ENERGY CORPORATION
ADJUSTED BOOK RETURN ON EQUITY (ROEs)
For the period ended December 31, 2018
dollars in millions

	Duke Energy Carolinas	Duke Energy Progress	Total Carolinas	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio Reportable Segments	Piedmont
Reported Net Income 2018	$ 1,071	$ 667	$ 1,738	$ 553	$ 393	$ 279 (2)	$ 124 (4)
Special Items (1)	234	118	352	63	8	-	40
Adjusted Net Income 2018	1,305	785	2,090	616	401	279	164
2018							
Equity	11,683	8,441	20,124	6,095	4,339	3,449 (3)	2,047 (5)
Goodwill	-	-	-	-	-	920	49
Equity less Goodwill	11,683	8,441	20,124	6,095	4,339	2,529	1,998
2017							
Equity	11,361	7,949	19,310	5,618	4,121	3,166 (3)	1,616 (5)
Goodwill	-	-	-	-	-	920	49
Equity less Goodwill	11,361	7,949	19,310	5,618	4,121	2,246	1,567
Average Equity less Goodwill			19,717	5,857	4,230	2,388	1,783
Adjusted Book ROEs			10.6%	10.5%	9.5%	11.7%	9.2%

(1) Costs to Achieve (CTA) Mergers net of tax, Severance, Regulatory and Legislative Impacts and Tax Reform.

(2) Net Income for 2018 equals Duke Energy Ohio reportable segments segment income, which already excludes CTA and cost savings initiatives, Severance and Sale of Retired Plant.

(3) Reconciliation of Duke Energy Ohio Equity to Equity of the reportable segments:

	2018	2017
Reported Equity for Duke Energy Ohio	3,445	3,163
Less: Non-Reg & Other	(4)	(3)
Duke Energy Ohio Reportable Segments Equity	3,449	3,166

(4) Piedmont Natural Gas Net Income excludes $5 million of income related to Investments in Gas Transmission Infrastructure.

(5) Reconciliation of Piedmont Natural Gas Equity to reported equity:

	2018	2017
Reported Equity for Piedmont Natural Gas	2,091	1,662
Less: Investments in Gas Transmission Infrastructure	44	46
Piedmont Natural Gas Adjusted Equity	2,047	1,616

DUKE ENERGY CORPORATION
ADJUSTED BOOK RETURN ON EQUITY (ROEs)
For the period ended December 31, 2017
dollars in millions

	Duke Energy Carolinas	Duke Energy Progress	Total Carolinas	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio Reportable Segments	Piedmont
Reported Net Income 2017	$ 1,214	$ 715	$ 1,929	$ 712	$ 354	$ 223 (2)	$ 133 (4)
Special Items (1)	28	(17)	11	(136)	58	(20)	25
Adjusted Net Income 2017	1,242	698	1,940	576	412	203	158
2017							
Equity	11,361	7,949	19,310	5,618	4,121	3,166 (3)	1,616 (5)
Goodwill	-	-	-	-	-	920	49
Equity less Goodwill	11,361	7,949	19,310	5,618	4,121	2,246	1,567
2016							
Equity	10,772	7,358	18,130	4,900	4,067	3,027 (3)	1,569 (5)
Goodwill	-	-	-	-	-	920	49
Equity less Goodwill	10,772	7,358	18,130	4,900	4,067	2,107	1,520
Average Equity less Goodwill			18,720	5,259	4,094	2,177	1,544
Adjusted Book ROEs			10.4%	11.0%	10.1%	9.3%	10.2%

(1) Costs to Achieve (CTA), Mergers net of tax, Regulatory Settlements, and Tax Reform.

(2) Net Income for 2017 equals Duke Energy Ohio reportable segments segment income, which already excludes CTA and cost savings initiatives.

(3) Reconciliation of Duke Energy Ohio Equity to Equity of the reportable segments:

	2017	2016
Reported Equity for Duke Energy Ohio	3,163	2,996
Less: Non-Reg & Other	(3)	(31)
Duke Energy Ohio Reportable Segments Equity	3,166	3,027

(4) Piedmont Natural Gas Net Income excludes $6 million of income related to Investments in Gas Transmission Infrastructure.

(5) Reconciliation of Piedmont Natural Gas Equity to reported equity:

	2017	2016
Reported Equity for Piedmont Natural Gas	1,662	1,672
Less: Investments in Gas Transmission Infrastructure	46	103
Piedmont Natural Gas Adjusted Equity	1,616	1,569

Duke Energy Corporation
2020 Forecasted Cash Flow Reconciliation, Required by SEC Regulation G
February 13, 2020
($ in millions)

		Forecast 2020
Primary Sources:		
Adjusted net income (1)	(a)	$3,870
Depreciation & amortization	(a)	5,470
Deferred and accrued taxes	(a)	805
Other sources / (uses), net	(a)	(235)
Total Sources		9,910
Primary Uses:		
Capital expenditures (including discretionary)	(b)	(11,825)
Dividends	(c)	(2,800)
Total Uses		(14,625)
Uses in Excess of Sources		(4,715)
Net Change in Financing		
Debt issuances	(c)	5,210
Debt maturities	(c, d)	(3,565)
Net Change in Debt		1,645
Common stock issuances	(c)	2,985
Net Change in Cash		($85)
Reconciliations to forecasted U.S. GAAP reporting amounts:		
Operating cash flow components, sum of (a) from above		$9,910
Reconciling items to GAAP cash flows from operating activities	(2)	(580)
Net cash provided by operating activities per GAAP Consolidated Statement of Cash Flows		$9,330
Investing cash flow components, (b) from above		($11,825)
Reconciling items to GAAP cash flows from investing activities	(2)	75
Net cash used in investing activities per GAAP Consolidated Statement of Cash Flows		($11,750)
Financing cash flow components, sum of (c) from above		$1,830
Reconciling items to GAAP cash flows from financing activities	(2)	505
Net cash provided by financing activities per GAAP Consolidated Statement of Cash Flows		$2,335
Debt maturities [(d) from above] includes "Notes payable and commercial paper" which is separately presented per GAAP Consolidated Statements of Cash Flows		
Net decrease in cash and cash equivalents per forecasted GAAP Consolidated Statements of Cash Flows		($85)

Notes:

(1) The forecasted adjusted net income of $3,870 million for 2020 is an illustrative amount based on the midpoint of Duke Energy's forecasted 2020 adjusted EPS outlook range of $5.05-$5.45 per share. Adjusted EPS is a non-GAAP financial measure as it represents basic and diluted EPS from continuing operations available to Duke Energy Corporation shareholders and adjusted for the per-share impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis, although it is reasonably possible such charges and credits could recur. The most directly comparable GAAP measure for adjusted EPS is reported basic and diluted EPS available to Duke Energy Corporation common shareholders, which includes the impact of special items. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items.

(2) Amount consists primarily of an adjustment for operating cashflow items (principally payments for asset retirement obligations) included in the "Capital expenditures (including discretionary)", which are combined for the GAAP reconciliation in Investing activities; an adjustment for investing cash flow items (principally cost of removal expenditures, proceeds from sales and maturities of available-for-sale securities and Other) included in the "Other sources/(uses), net", which are combined for the GAAP reconciliation in Operating activities, and ; an adjustment for financing cash flow items (principally proceeds from Noncontrolling Interests initial investments, payments for interest on preferred debt/equity content securities, dividends on preferred stock, common equity forward transaction costs and Other) included in the "Adjusted net income", "Other sources/(uses), net" and "Capital expenditures (including discretionary)', which are combined for the GAAP reconciliation in Operating activities and Investing activities.

FFO to Debt Calculation
Duke Energy Corporation
(in millions)

		Year Ended December 31, 2019 Actual
Cash From Operations	$	8,209
Adjust for Working Capital		250
Coal ash ARO spend		746
Include Capitalized Interest as cost		(159)
Hybrid interest adjustment		10
Preferred stock adjustment		(21)
CR3 securitization adjustment		(54)
ACP construction loan interest adjustment		(32)
AMT refund adjustment (1)		(287)
Lease-imputed FFO adjustment (D&A)		240
Funds From Operations	**$**	**8,903**
Notes payable and commercial paper	$	3,135
Current maturities of LT debt		3,141
LT debt		54,985
Less: Purchase Accounting adjustments		(1,912)
CR3 securitization		(1,111)
Underfunded Pension		350
ACP construction loan		827
Hybrid debt adjustment		(250)
Preferred stock adjustment		1,000
Lease-imputed debt		1,640
Total Balance Sheet Debt (Including ST)	**$**	**61,805**
Working capital detail, excluding MTM		
Receivables	$	78
Inventory		(122)
Other current assets		10
Accounts payable		(164)
Taxes accrued		(224)
Other current liabilities		172
	$	**(250)**
FFO / Debt		**14.4%**

(1) AMT refund adjustment is an expected 2020 cash inflow from the IRS related to AMT refunds that Duke Energy will receive as a result of the 2017 Tax Act. The 2020 AMT refund is included in the 2019 GAAP cash flow statement as deferred income taxes and change in other current assets. The change in other current assets is part of working capital, which is added back to the cash from operations. Therefore, the AMT refund adjustment is required to reduce cash from operations so there is no impact in 2019 for the 2020 expected AMT Refund.

In the 2018 Funds From Operations, a similar adjustment should have been made for the $573 million AMT refund. Had the adjustment been made, the Funds From Operations would have been reduced by $573 million. Starting in 2019 and going forward, receipt of the AMT refund will consistently be included in Fund From Operations in the year the cash is received.

FFO to Debt Calculation
Duke Energy Carolinas
(in millions)

		Year Ended December 31, 2019 Actual
Cash From Operations	$	2,709
Adjust for Working Capital		144
ARO spend		278
Include Capitalized Interest as cost		(30)
Lease-imputed FFO adjustment (D&A)		43
Funds From Operations	**$**	**3,144**
Current maturities of LT debt	$	458
LT debt		11,142
LT debt payable to affiliates		300
Notes payable to affiliated companies		29
Lease imputed debt		129
Total Balance Sheet Debt (Including ST)	**$**	**12,058**
Working capital detail, excluding MTM		
Receivables	$	(21)
Receivables from affiliates		68
Inventory		(48)
Other current assets		(73)
Accounts payable		(50)
Accounts payable to affiliates		(20)
Taxes accrued		(127)
Other current liabilities		127
	$	**(144)**
FFO / Debt		**26.1%**

FFO to Debt Calculation
Duke Energy Progress
(in millions)

		Year Ended December 31, 2019 Actual
Cash From Operations	$	1,823
Adjust for Working Capital		(92)
Coal ash ARO spend		390
Include Capitalized Interest as cost		(28)
Lease-imputed FFO adjustment (D&A)		56
Funds From Operations	**$**	**2,149**
Notes payable to affiliated companies	$	66
Current maturities of LT debt		1,006
LT debt		7,902
LT debt payable to affiliates		150
Lease imputed debt		391
Total Balance Sheet Debt (Including ST)	**$**	**9,515**
Working capital detail, excluding MTM		
Receivables	$	21
Receivables from affiliates		(29)
Inventory		20
Other current assets		101
Accounts payable		32
Accounts payable to affiliates		(75)
Taxes accrued		(46)
Other current liabilities		68
	$	**92**
FFO / Debt		**22.6%**

FFO to Debt Calculation
Duke Energy Florida
(in millions)

		Year Ended December 31, 2019 Actual
Cash From Operations	$	1,478
Adjust for Working Capital		(178)
Coal ash ARO spend		22
Include Capitalized Interest as cost		(3)
Adjust for CR3		(54)
Lease-imputed FFO adjustment (D&A)		79
Funds From Operations	**$**	**1,344**
Notes payable to affiliated companies	$	-
Current maturities of LT debt		571
LT debt		7,416
Adjust for CR3		(1,111)
Lease imputed debt		401
Underfunded Pension		77
Total Balance Sheet Debt (Including ST)	**$**	**7,354**
Working capital detail, excluding MTM		
Receivables	$	26
Receivables from affiliates		17
Inventory		42
Other current assets		156
Accounts payable		(36)
Accounts payable to affiliates		40
Taxes accrued		(31)
Other current liabilities		(36)
	$	**178**
FFO / Debt		**18.3%**

FFO to Debt Calculation
Duke Energy Indiana
(in millions)

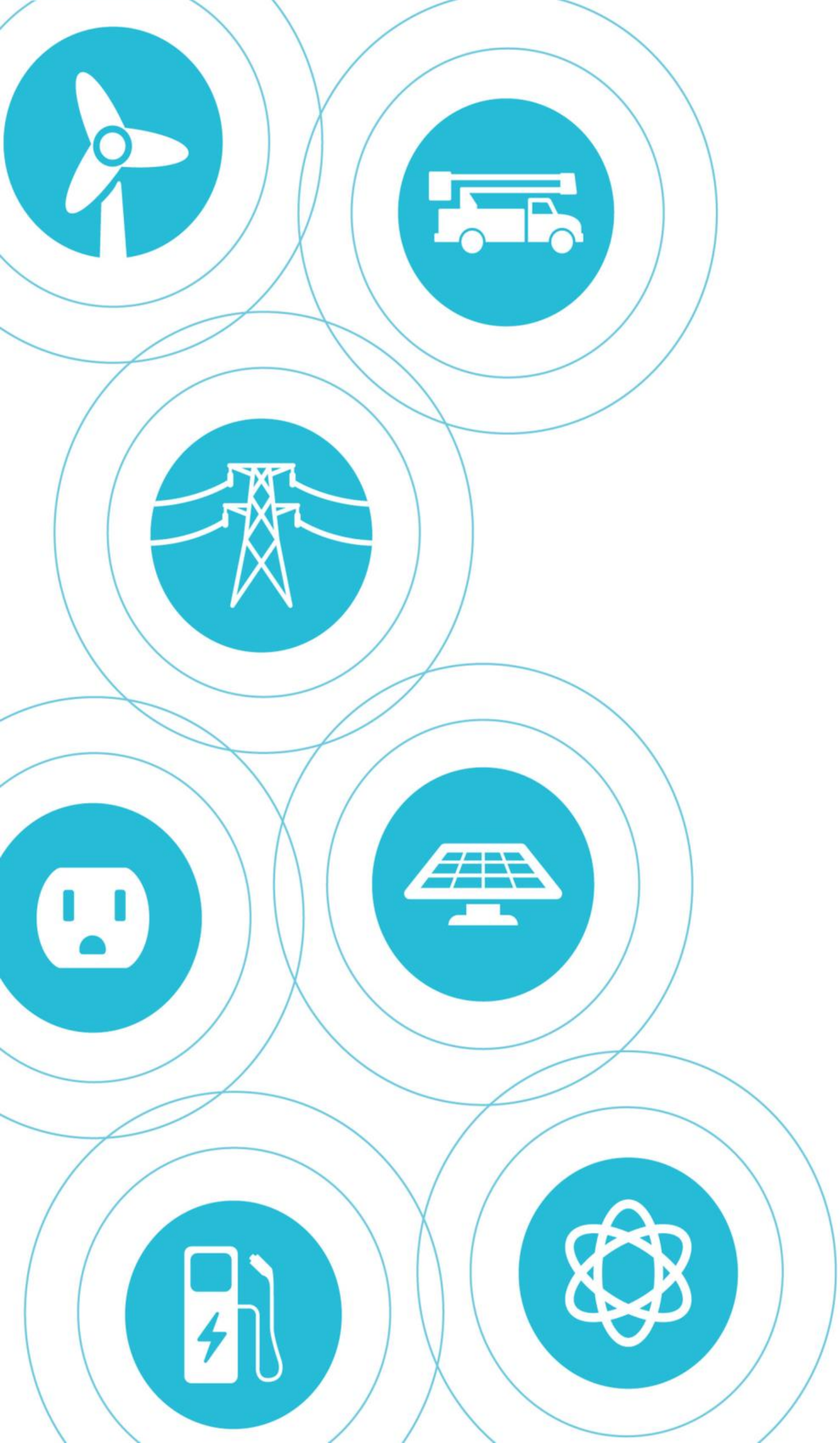
		Year Ended December 31, 2019 Actual
Cash From Operations	$	997
Adjust for Working Capital		2
Coal ash ARO spend		48
Include Capitalized Interest as cost		(26)
Lease-imputed FFO adjustment (D&A)		18
Funds From Operations	**$**	**1,039**
Notes payable to affiliated companies	$	30
Current maturities of LT debt		503
LT debt		3,404
LT debt payable to affiliates		150
CRC		186
Lease imputed debt		58
Total Balance Sheet Debt (Including ST)	**$**	**4,331**
Working capital detail, excluding MTM		
Receivables	$	(8)
Receivables from affiliates		41
Inventory		(95)
Other current assets		76
Accounts payable		(10)
Accounts payable to affiliates		4
Taxes accrued		(25)
Other current liabilities		15
	$	**(2)**
FFO / Debt		**24.0%**

FFO to Debt Calculation
Duke Energy Ohio
(in millions)

		Year Ended December 31, 2019 Actual
Cash From Operations	$	526
Adjust for Working Capital		(19)
Coal Ash ARO spend		8
Include capitalized Interest as cost		(22)
Lease-imputed FFO adjustment (D&A)		10
Funds From Operations	**$**	**503**
Notes payable to affiliated companies	$	312
Current maturities of LT debt		-
LT debt		2,594
LT debt payable to affiliates		25
CRC		165
Lease imputed debt		22
Total Balance Sheet Debt (Including ST)	**$**	**3,118**
Working capital detail, excluding MTM		
Receivables	$	20
Receivables from affiliates		22
Inventory		(9)
Other current assets		(5)
Accounts payable		(17)
Accounts payable to affiliates		(10)
Taxes accrued		17
Other current liabilities		1
	$	**19**
FFO / Debt		**16.1%**

FFO to Debt Calculation
Piedmont Natural Gas
(in millions)

		Year Ended December 31, 2019 Actual
Cash From Operations	$	409
Adjust for Working Capital		88
Include Capitalized Interest as cost		(26)
Lease-imputed FFO adjustment (D&A)		4
Funds From Operations	**$**	**475**
Notes payable to affiliated companies	$	476
Current maturities of LT debt		-
LT debt		2,384
Lease imputed debt		27
Total Balance Sheet Debt (Including ST)	**$**	**2,887**
Working capital detail, excluding MTM		
Receivables	$	28
Receivables from affiliates		12
Inventory		(2)
Other current assets		(25)
Accounts payable		(7)
Accounts payable to affiliates		(35)
Taxes accrued		(60)
Other current liabilities		1
	$	**(88)**
FFO / Debt		**16.5%**



DUKE ENERGY®

Q4 / 2020

EARNINGS REVIEW AND BUSINESS UPDATE

Lynn Good / *Chair, President and CEO*
Steve Young / *Executive Vice President and CFO*

February 11, 2021

Safe Harbor statement

This presentation includes forward-looking statements within the meaning of the federal securities laws. Actual results could differ materially from such forward-looking statements. The factors that could cause actual results to differ are discussed herein and in Duke Energy's SEC filings, available at www.sec.gov.

Regulation G disclosure

In addition, today's discussion includes certain non-GAAP financial measures as defined under SEC Regulation G. A reconciliation of those measures to the most directly comparable GAAP measures is available in the Appendix herein and on our Investor Relations website at www.duke-energy.com/investors/.

Safe harbor statement

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions and can often be identified by terms and phrases that include "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," "target," "guidance," "outlook" or other similar terminology. Various factors may cause actual results to be materially different than the suggested outcomes within forward-looking statements; accordingly, there is no assurance that such results will be realized. These factors include, but are not limited to: The impact of the COVID-19 pandemic; State, federal and foreign legislative and regulatory initiatives, including costs of compliance with existing and future environmental requirements, including those related to climate change, as well as rulings that affect cost and investment recovery or have an impact on rate structures or market prices; The extent and timing of costs and liabilities to comply with federal and state laws, regulations and legal requirements related to coal ash remediation, including amounts for required closure of certain ash impoundments, are uncertain and difficult to estimate; The ability to recover eligible costs, including amounts associated with coal ash impoundment retirement obligations and costs related to significant weather events, and to earn an adequate return on investment through rate case proceedings and the regulatory process; The costs of decommissioning nuclear facilities could prove to be more extensive than amounts estimated and all costs may not be fully recoverable through the regulatory process; Costs and effects of legal and administrative proceedings, settlements, investigations and claims; Industrial, commercial and residential growth or decline in service territories or customer bases resulting from sustained downturns of the economy and the economic health of our service territories or variations in customer usage patterns, including energy efficiency efforts and use of alternative energy sources, such as self-generation and distributed generation technologies; Federal and state regulations, laws and other efforts designed to promote and expand the use of energy efficiency measures and distributed generation technologies, such as private solar and battery storage, in Duke Energy service territories could result in customers leaving the electric distribution system, excess generation resources as well as stranded costs; Advancements in technology; Additional competition in electric and natural gas markets and continued industry consolidation; The influence of weather and other natural phenomena on operations, including the economic, operational and other effects of severe storms, hurricanes, droughts, earthquakes and tornadoes, including extreme weather associated with climate change; Changing customer expectations and demands including heightened emphasis on environmental, social and governance concerns; The ability to successfully operate electric generating facilities and deliver electricity to customers including direct or indirect effects to the company resulting from an incident that affects the U.S. electric grid or generating resources; Operational interruptions to our natural gas distribution and transmission activities; The availability of adequate interstate pipeline transportation capacity and natural gas supply; The impact on facilities and business from a terrorist attack, cybersecurity threats, data security breaches, operational accidents, information technology failures or other catastrophic events, such as fires, explosions, pandemic health events or other similar occurrences; The inherent risks associated with the operation of nuclear facilities, including environmental, health, safety, regulatory and financial risks, including the financial stability of third-party service providers; The timing and extent of changes in commodity prices and interest rates and the ability to recover such costs through the regulatory process, where appropriate, and their impact on liquidity positions and the value of underlying assets; The results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings, interest rate fluctuations, compliance with debt covenants and conditions and general market and economic conditions; Credit ratings of the Duke Energy Registrants may be different from what is expected; Declines in the market prices of equity and fixed-income securities and resultant cash funding requirements for defined benefit pension plans, other post-retirement benefit plans and nuclear decommissioning trust funds; Construction and development risks associated with the completion of the Duke Energy Registrants' capital investment projects, including risks related to financing, obtaining and complying with terms of permits, meeting construction budgets and schedules and satisfying operating and environmental performance standards, as well as the ability to recover costs from customers in a timely manner, or at all; Changes in rules for regional transmission organizations, including changes in rate designs and new and evolving capacity markets, and risks related to obligations created by the default of other participants; The ability to control operation and maintenance costs; The level of creditworthiness of counterparties to transactions; The ability to obtain adequate insurance at acceptable costs; Employee workforce factors, including the potential inability to attract and retain key personnel; The ability of subsidiaries to pay dividends or distributions to Duke Energy Corporation holding company (the Parent);The performance of projects undertaken by our nonregulated businesses and the success of efforts to invest in and develop new opportunities; The effect of accounting pronouncements issued periodically by accounting standard-setting bodies; The impact of U.S. tax legislation to our financial condition, results of operations or cash flows and our credit ratings; The impacts from potential impairments of goodwill or equity method investment carrying values; and the ability to implement our business strategy, including enhancing existing technology systems.

Additional risks and uncertainties are identified and discussed in the Duke Energy Registrants' reports filed with the SEC and available at the SEC's website at sec.gov. In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than described. Forward-looking statements speak only as of the date they are made and the Duke Energy Registrants expressly disclaim an obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Financial highlights

$1.72 / $5.12

2020 REPORTED / ADJUSTED EPS

ADJUSTED EPS AT MIDPOINT OF NARROWED RANGE

$5.00 - $5.30

2021 ADJUSTED EPS GUIDANCE RANGE

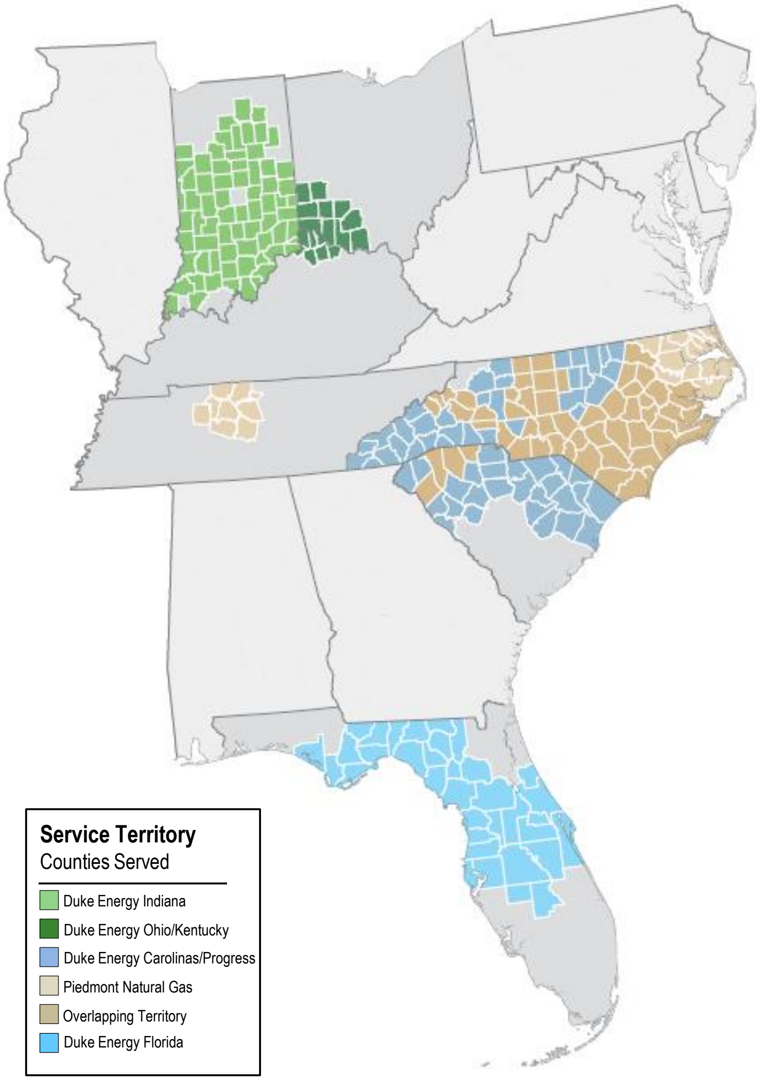
5% – 7%

GROWTH RATE THROUGH 2025 OFF 2021 MIDPOINT OF $5.15[(1)]

(1) *Based on adjusted EPS*

SWIFT RESPONSE TO 2020 HEADWINDS

Recent accomplishments provide clarity and momentum



CAROLINAS

- ✓ NC coal ash settlement with AG, Public Staff and Sierra Club
- ✓ NC rate case settlement on ROE, capital structure, grid deferral, tax reform
- ✓ Innovative IRPs outline six pathways to achieve climate goals
- ✓ EV pilots approved in NC and SC
- ✓ Settlements reached on interconnection queue and net metering

FLORIDA

- ✓ Settlement establishes multi-year rate plan through 2024
- ✓ $1 billion Clean Energy Connection supports 750MW solar
- ✓ 10-year, $6 billion Storm Protection Plans

INDIANA

- ✓ Announced sale of 19.9% minority interest for $2.05 billion to GIC; source of efficient capital at attractive valuation
- ✓ 2020 rate case approval includes two base rate step-ups based on forward looking test year

AND MORE

- ✓ Announced >700MW of regulated and commercial renewables
- ✓ Settlement in Piedmont TN rate case
- ✓ Moved past ACP

SOLID FOUNDATION POSITIONS US WELL AS WE LOOK FORWARD

Clear vision for the future – to lead the energy transition

Our Clean Energy Transformation

≥50% REDUCTION IN CO_2 EMISSIONS AND NET-ZERO METHANE EMISSIONS BY 2030 ON THE WAY TO

NET-ZERO CO_2 BY 2050

Transform the system
robust **$59 billion** capital plan focused on clean generation and grid investments

Shape the landscape
to accelerate the transition, with an eye on reliability and affordability

Deliver value
for customers and shareholders

Near-term initiatives

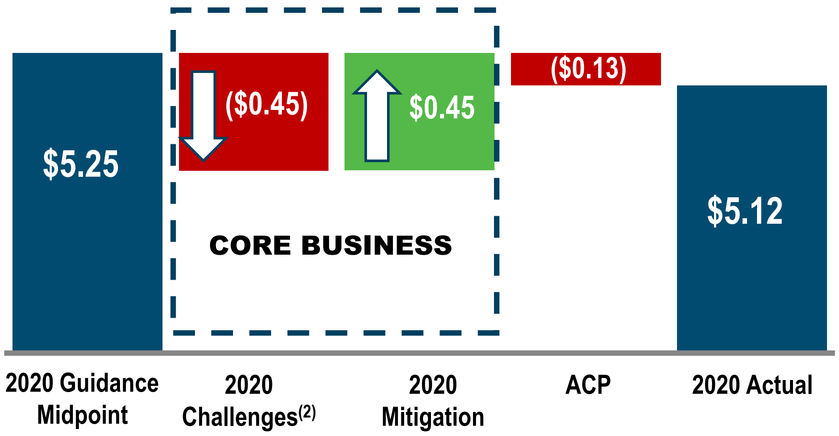
- Carolinas → Move through IRP process as we engage policymakers in both states
- Indiana → 2021 IRP filing in November
- Florida → Settlement outlines clear path for renewables and EV investment through 2024
- Federal → Engaging policymakers to advance shared objectives on climate

(1) *Based on adjusted EPS*

5-7% GROWTH[1] DRIVEN BY AGGRESSIVE CLIMATE STRATEGY

Financial highlights

2020 PLAN TO 2020 ACTUALS[1]



$5.00 - $5.30

2021 ADJUSTED EPS GUIDANCE RANGE

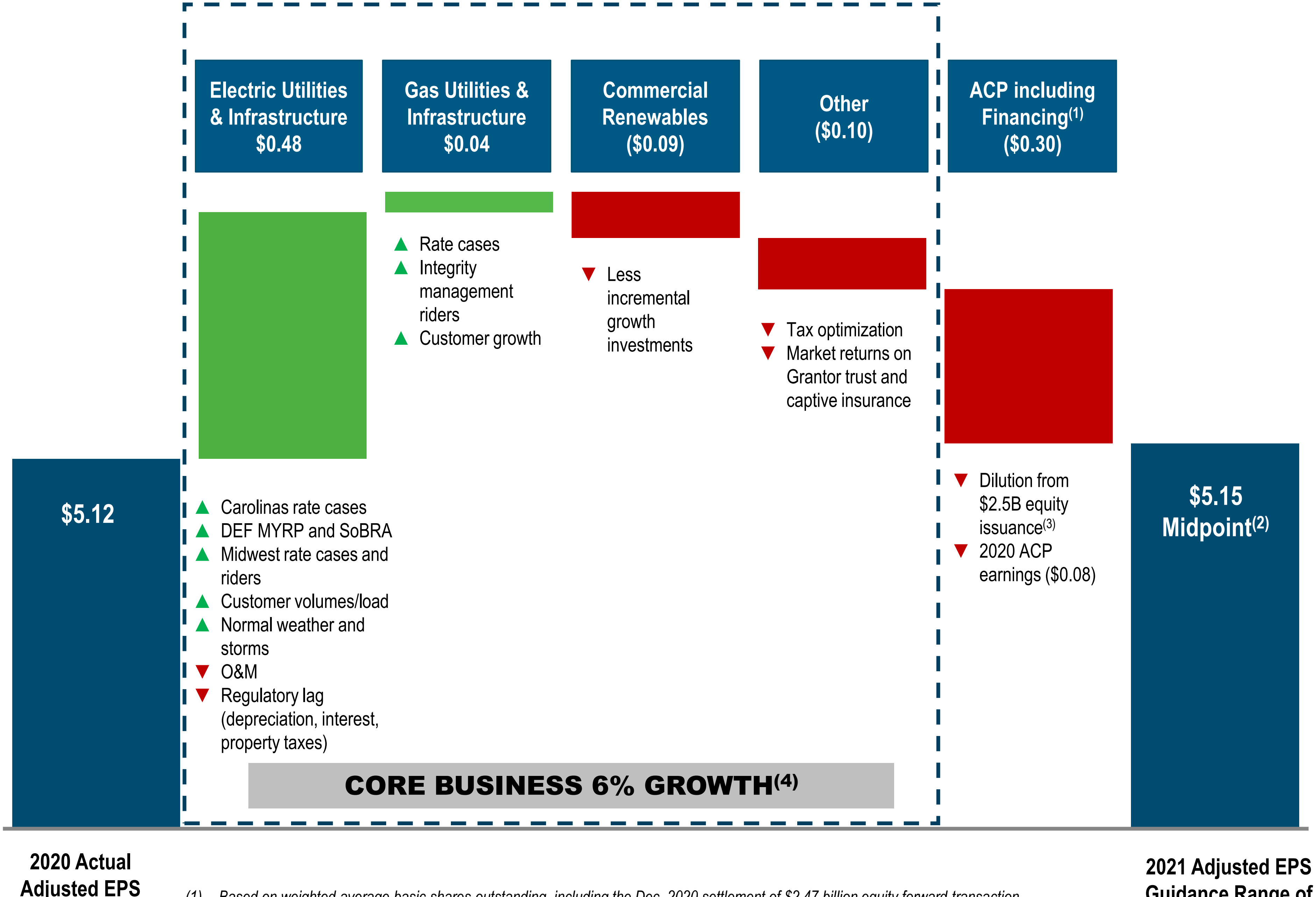
KEY MESSAGES

- Delivered 2020 reported EPS of $1.72 and adjusted EPS of $5.12; within the original and updated guidance range
- Demonstrated clear agility in managing:
  - COVID-19 impact of ($0.28) EPS inclusive of load, waived fees and COVID costs, net of deferrals
  - Weather and storms ($0.11) EPS
  - Delivered significant O&M and other mitigation of $0.45 EPS
  - ACP cancellation ($0.13) EPS
- Achieved solid year-over-year growth from our core businesses
  - Electric Utilities and Infrastructure rate case outcomes (NC, SC, FL, IN)
  - Gas Utilities and Infrastructure NC rate case outcome and safety and integrity riders
  - Commercial renewable growth

(1) Based on adjusted EPS
(2) 2020 Challenges include: ($0.28) COVID load and non-deferrable incremental costs; ($0.11) Weather and storms; and Other ($0.06)

COMPANY WELL POSITIONED FOR GROWTH

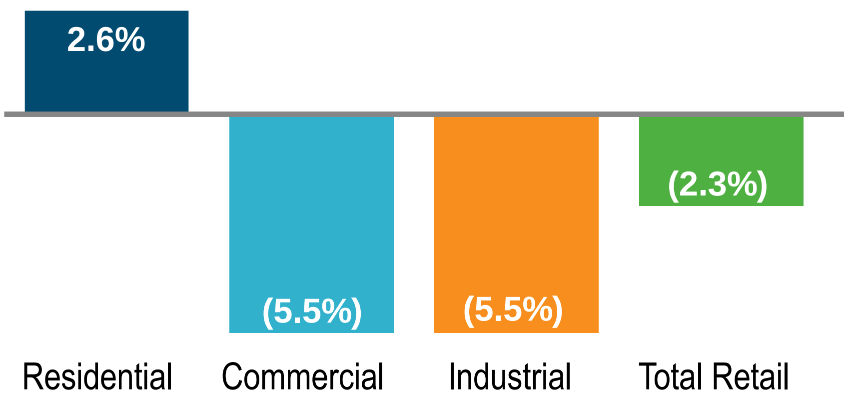
2021 Financial outlook – adjusted EPS waterfall



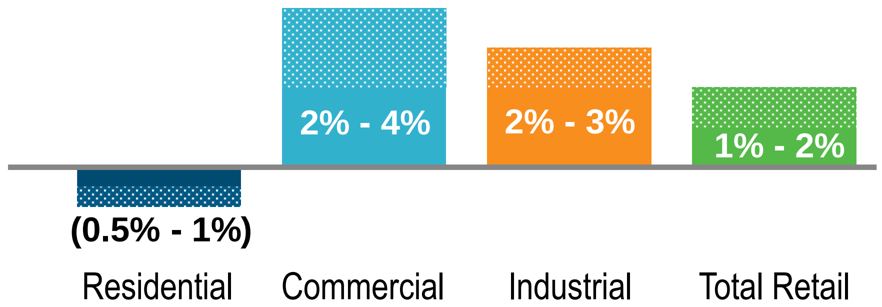
(1) *Based on weighted average basic shares outstanding, including the Dec. 2020 settlement of $2.47 billion equity forward transaction.*
(2) *Midpoint of 2021 adjusted EPS guidance range of $5.00 - $5.30*
(3) *Segment EPS drivers are calculated based upon prior year share amounts*
(4) *Based on adjusted EPS*

Retail electric volumes

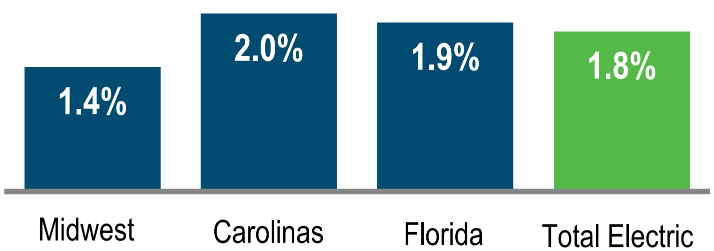
2020 RETAIL ELECTRIC VOLUMES(1)



FORECASTED 2021 RETAIL ELECTRIC VOLUMES(2)



2020 GROWTH IN RESIDENTIAL CUSTOMERS



KEY MESSAGES

- Expect favorable volume relative to 2020 as economic recovery continues
  - 2021 volumes not back to pre-COVID levels; expect rebound to 2019 actual levels in 2022
- Forecast supported by customer growth that continues to trend above the national average
  - Our jurisdictions represent 4 of the top 8 states for inbound moves in 2020(3)
  - North Carolina named *2020 State of the Year*(4) recognizing $6 billion of announced corporate investment during 2020, including plans for 20,000 new jobs

(1) Compared to 2019 actuals
(2) Compared to 2020 actuals
(3) Source: North American Moving Services
(4) Source: Business Facilities Magazine

GROWING CUSTOMER BASE SUPPORTS NEED FOR INCREASED CAPITAL INVESTMENTS

Cost management continues to be a core competency

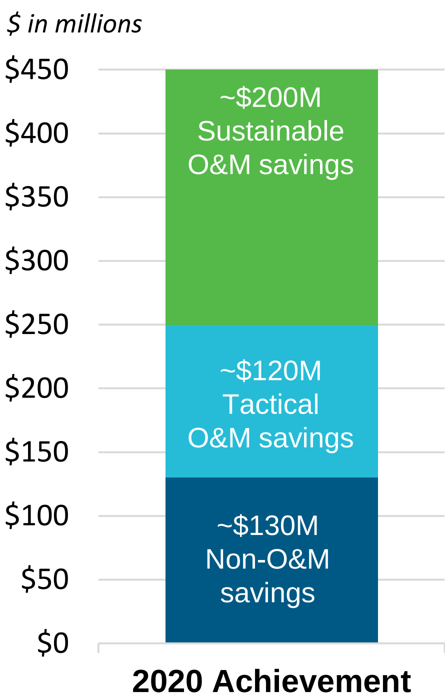
2020 HIGHLIGHTS TACTICAL AND SUSTAINABLE COST MANAGEMENT

- Activated agile business levers in 2020 to achieve $450 million of mitigation
  - Total 2020 O&M savings of ~$320 million, of which ~65% expected to be sustainable

BUSINESS TRANSFORMATION CONTINUES TO PRODUCE SUSTAINABLE SAVINGS

- Net regulated Electric & Gas O&M has decreased ~1% annually since 2016; expect this trend to continue through 2025

2020 MITIGATION(1)



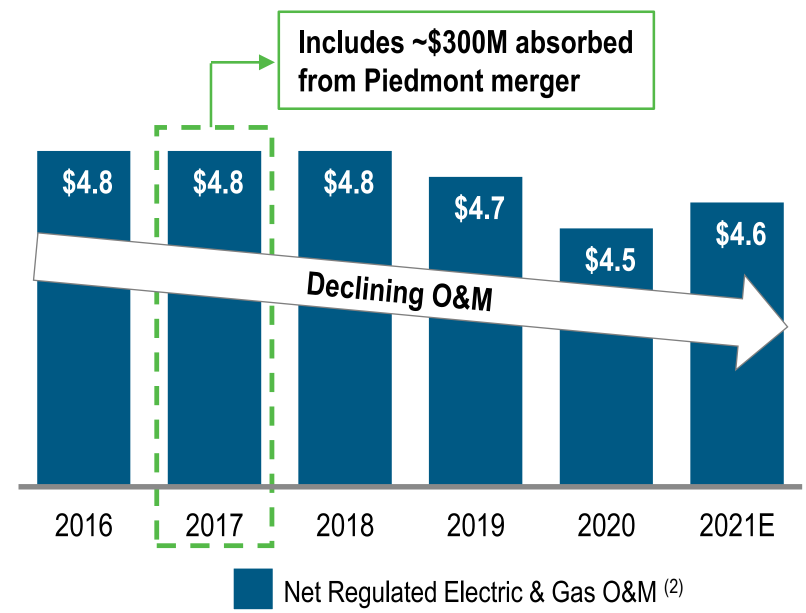
Sustainable O&M savings
- Versatile workforce
- Digital capabilities
- General business expenses
- Real estate optimization

Tactical O&M savings
- Outage timing
- Variable compensation
- Hiring freeze

Non O&M savings
- Tax optimization
- Low interest rates

O&M COST MANAGEMENT(2)

($ IN BILLIONS)

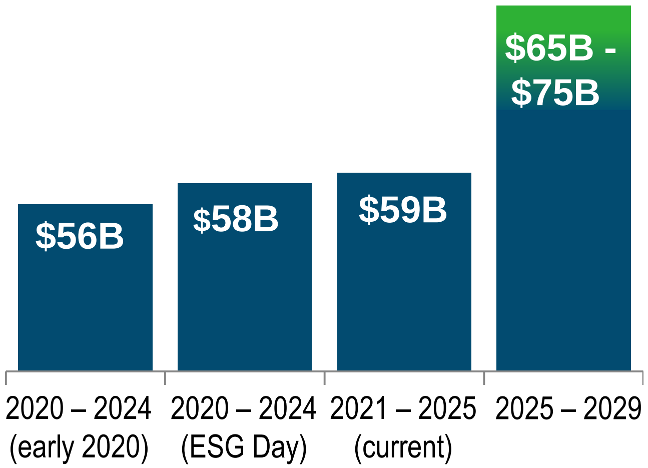


(1) *Mitigation includes contract and employee labor costs including overtime and variable compensation, employee expenses, interest and tax savings and operational efficiencies*

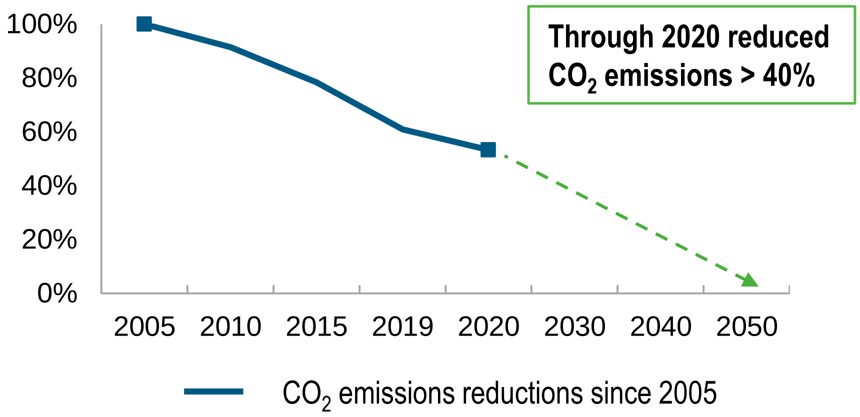
(2) *Net regulated Electric and Gas O&M is a non-GAAP measure. For a description of this non-GAAP item and a reconciliation to GAAP O&M, see accompanying materials at www.duke-energy.com/investors*

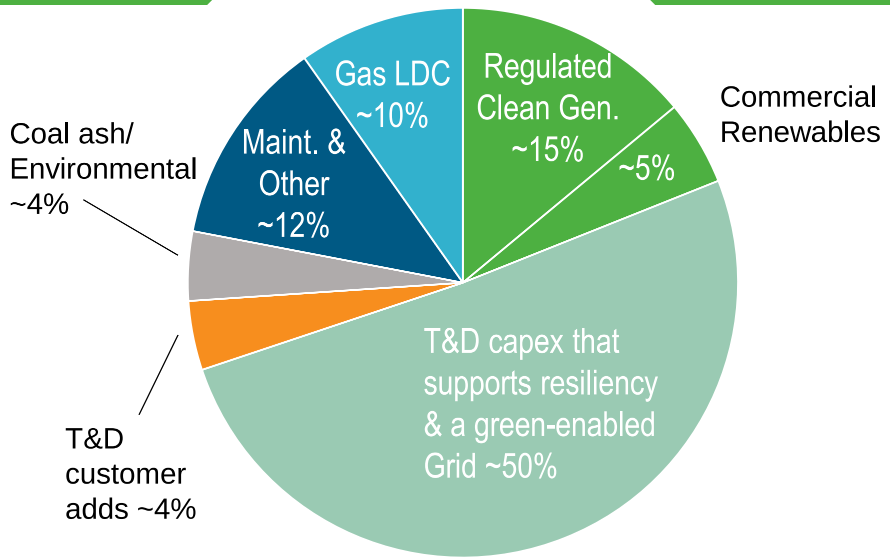
Capital plan focused on clean energy transition

Growing 5-year capex profile…



…supports emission reductions as we drive toward net-zero





$59 BILLION CAPITAL PLAN FOCUSED ON CLEAN ENERGY TRANSITION

- Drives rate base CAGR of ~6.5% over 5-year plan
- Accelerated coal plant retirements
- Grid investments to enable renewables and energy storage, resiliency and dynamic power flows
- Clean energy – mix of solar, storage and nuclear

Projected growth over five-year plan

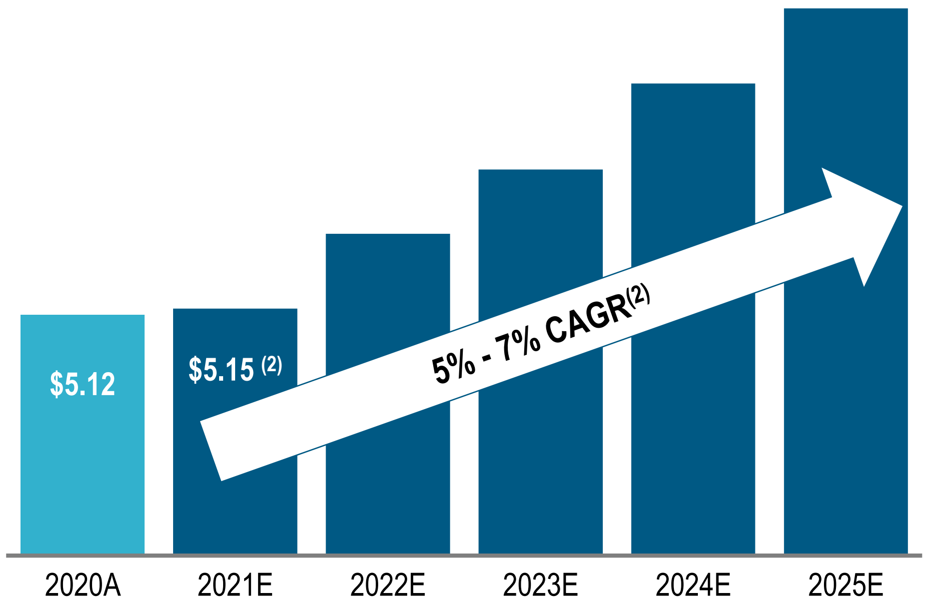
UPSIDES TO PLAN

- Acceleration of clean energy transformation
- Sustainable cost transformation
- Federal legislation, including infrastructure
- Stronger and faster economic recovery

ITEMS TO MONITOR

- Economic recovery from pandemic
- Weather and storms

5-YEAR ADJUSTED EPS GROWTH PLAN[1]



5 – 7%

GROWTH THROUGH 2025 OFF 2021 MIDPOINT OF $5.15

(1) Based on adjusted EPS
(2) Based off the midpoint of 2021 adjusted EPS guidance range ($5.15)

Balance sheet supports our long-term growth strategy

COMMITTED TO STRONG CASH FLOWS SUPPORTIVE OF CREDIT RATINGS

- Duke Energy operates in constructive jurisdictions, with a de-risked financial plan
  - Rate case orders or settlements in Carolinas, Indiana, Florida and Tennessee
- Proven capability to drive operational efficiencies
  - Track record of cost management and capital optimization
  - Pension plan fully funded (no expected contributions in 5-year plan)
- Creative capital raising supports credit
  - Partnership with GIC to secure minority investment in DEI
  - Commercial renewables joint venture with John Hancock
  - Tax equity partnerships for Commercial Renewables
- Targeting 14% FFO/Debt throughout the 5-year plan
  - Provides adequate cushion to absorb unplanned events and maintain current credit profile

NO COMMON EQUITY ISSUANCES IN 5-YEAR PLAN

Our investor value proposition

DUK LISTED NYSE

A STRONG LONG-TERM RETURN PROPOSITION

DUK LISTED NYSE

4.1%

DIVIDEND YIELD(1) WITH LONG-TERM DIVIDEND **GROWTH COMMITMENT**(2)

~10%

ATTRACTIVE RISK-ADJUSTED **TOTAL SHAREHOLDER RETURN**(3)

5-7%

LONG-TERM **EPS GROWTH**(4) THROUGH 2025

CONSTRUCTIVE JURISDICTIONS, LOWER-RISK REGULATED INVESTMENTS AND BALANCE SHEET STRENGTH

(1) *As of Feb. 9, 2021*
(2) *Subject to approval by the Board of Directors.*
(3) *Total shareholder return proposition at a constant P/E ratio*
(4) *Based on adjusted EPS*

APPENDIX

2021 agreements provide clarity

CLARITY ON NC COAL ASH COST RECOVERY

- Settlement reached with NC AG, NC Public Staff and Sierra Club
- Resolves 2017 cases on remand and pending 2019 rate cases
- Provides greater clarity on recovery through early 2030
- Preserves equity return at a reduced ROE (- 150 bps)
- $1.1B one-time charge
- Accelerates customer savings during pandemic
- Subject to NCUC approval
- Expect DEC rate case order in the coming weeks

DUKE ENERGY FLORIDA SETTLEMENT

- Clarity through 2024
- ROE band of 8.85% to 10.85%, with innovative trigger mechanism that insulates against rising interest rates
- Clean Energy Connection solar buildout: 750 MW to be built 2022-2024 ($1B investment)
- EV Charging Station program ($54M investment)
- Accelerated depreciation for coal plants (from 2042 to 2034)
- Vision Florida program funds $100M in emerging technologies
- FPSC approval expected Q2

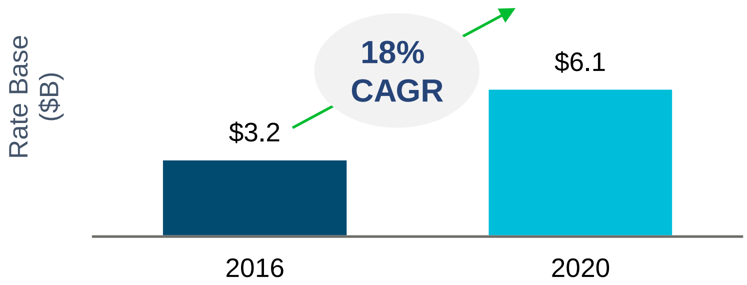
DUKE ENERGY INDIANA MINORITY INTEREST SALE

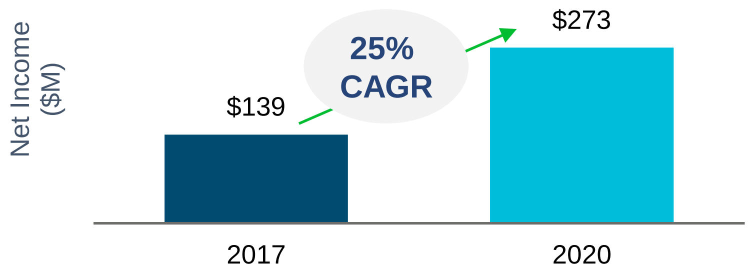
- Selling 19.9% interest in DEI for $2.05B to GIC
- Source of efficient capital at attractive valuation
- Proceeds to support increased growth investments
- Customized dual tranche closing aligns with capital needs
- Addresses common equity needs through 2025
- Subject to FERC approval and Committee on Foreign Investment in the United States (CFIUS) clearance

LANDMARK AGREEMENTS PROVIDE EARNINGS VISIBILITY

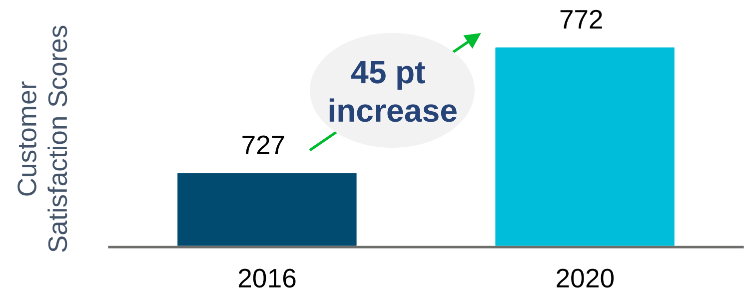
Recent strategic decisions have been in the best interest of shareholders

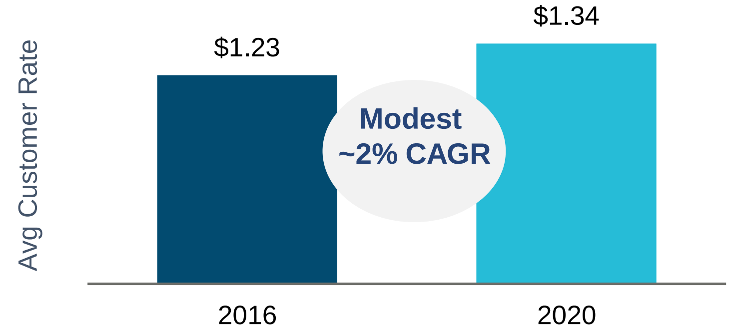
2016 PIEDMONT ACQUISITION HAS BEEN GOOD FOR SHAREHOLDERS…





… AND GOOD FOR PIEDMONT CUSTOMERS





DUKE ENERGY HAS OPTIMIZED ITS PORTFOLIO TO REDUCE RISK AND GROW EARNINGS

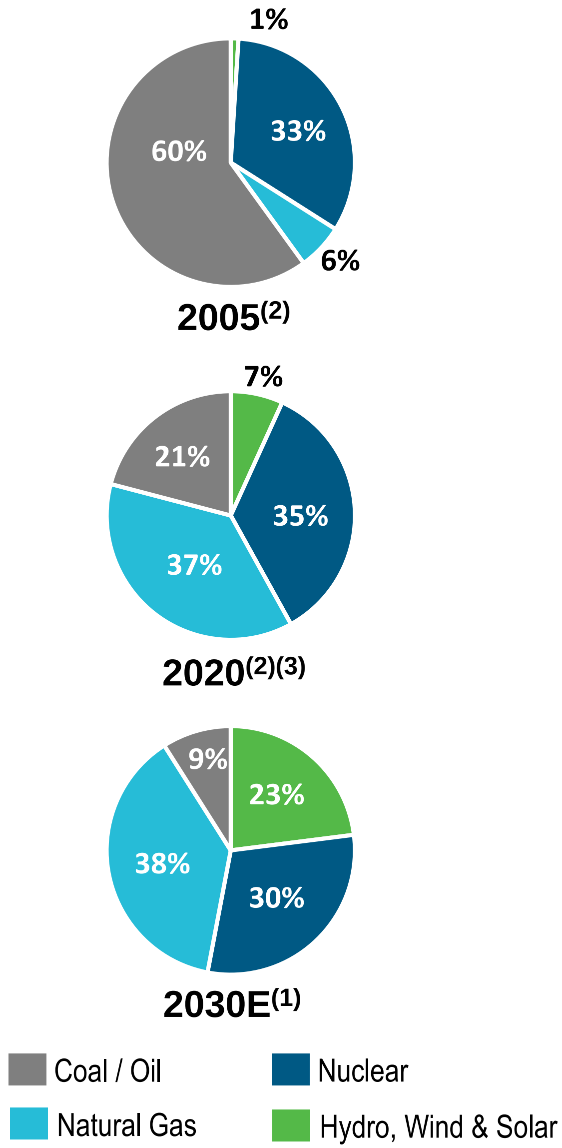
- Sale of midwest merchant generation
- Sale of international generation portfolio
- Sale of DukeNet fiber/telecom business
- Joint venture of commercial renewables portfolio
- Minority interest sale of Duke Energy Indiana
- Forgoing certain investments due to risk profile

STRONG TRACK RECORD OF DELIVERING SHAREHOLDER VALUE AND REDUCING RISK

Sustainability / Environmental Social and Governance (ESG)

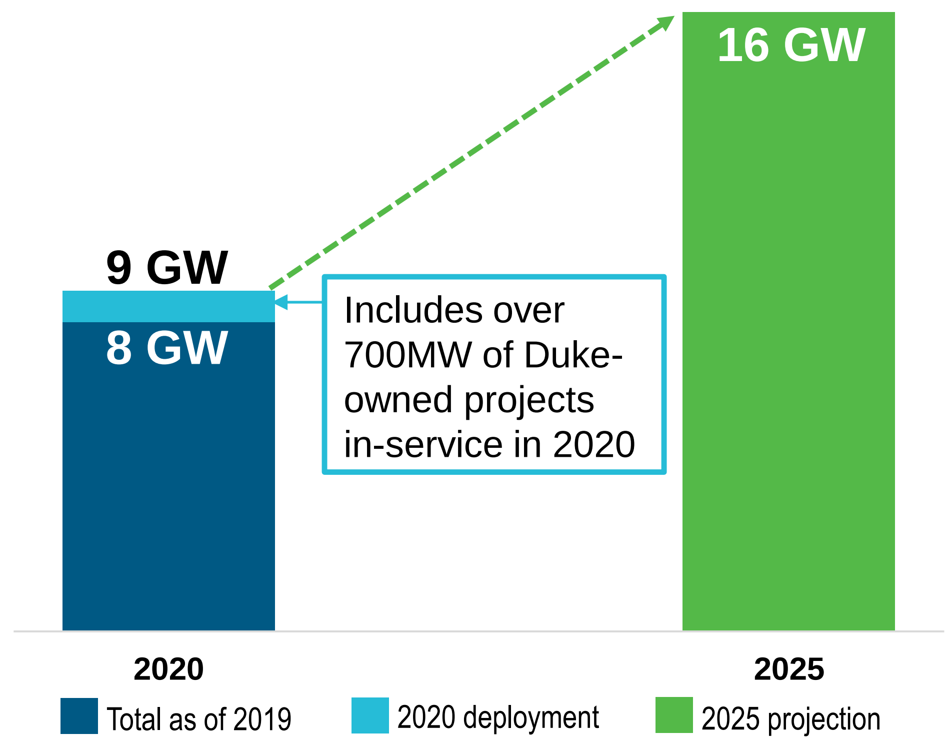
Clean energy transformation

FUEL DIVERSITY (MWh OUTPUT)



KEY MESSAGES

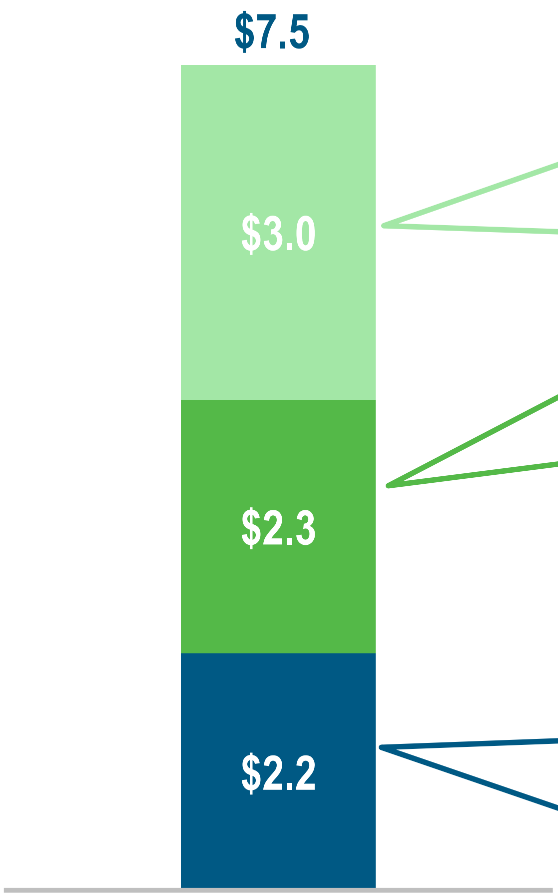
- Since 2005, decreased CO_2 emissions over 40%, sulfur dioxide emissions by over 95% and nitrogen oxides emissions by over 80%(1)
- Renewables deployment expected to accelerate through 2025 to reach 16 GW goal(4)
- By 2050, renewables projected to be Duke Energy's largest source of energy, making up over 40% of our generation capacity



(1) From 2005 levels. 2030 estimate and year to year reductions will be influenced by customer demand for electricity, weather, fuel and purchased power prices, and other factors
(2) 2005 and 2020 data based on Duke's ownership share of U.S. generation assets as of Dec. 31, 2020
(3) 2020 data excludes 9,300 GWh of purchased renewables, equivalent to ~4% of Duke's output
(4) Includes renewables owned, operated and under contract.

Financing practices supportive of ESG commitments

$7.5 BILLION OF CAPITAL RAISED TO SUPPORT ENVIRONMENTAL & SOCIAL (E&S) INITIATIVES OVER THE LAST 5 YEARS



2016-2020 E&S Capital Raised
($ in Billions)

Commercial Renewables

- $3.0 billion of external financing to fund the development or purchase of ~3 GWs of solar and wind projects since 2016
- Total external financing includes $1.5 billion of tax-equity

Green Bonds

- $2.3 billion raised by three utilities: DE Carolinas, DE Progress, and DE Florida
- Supports Duke's continued investments in solar energy, battery storage, and hydro pumped-storage projects

Diversity & Inclusion (D&I) Transactions

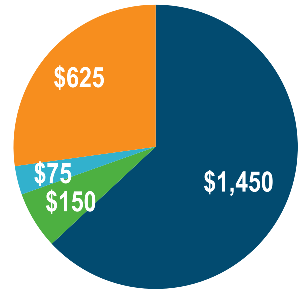
- $2.2 billion raised utilizing diversity-owned broker-dealers in prominent, active roles on capital market transactions
- $5.0 million deposited with local African-American owned bank supports minority-owned businesses, individuals, and low-income communities

2020 performance and 2021 guidance supplemental information

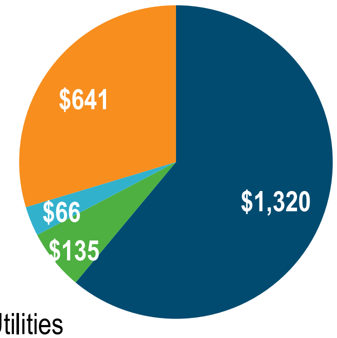
Key 2021 adjusted earnings guidance assumptions

($ in millions)	Original 2020 Assumptions	2020 Actual	2021 Assumptions
Adjusted segment income/ (expense) (1):			
Electric Utilities & Infrastructure	$3,640	$3,545	$3,900
Gas Utilities & Infrastructure	$530	$441	$415
Commercial Renewables	$240	$286	$220
Other	($540)	($501)	($575)
Duke Energy Consolidated	$3,870	$3,771	$3,960
Additional consolidated information:			
Effective tax rate including noncontrolling interests and preferred dividends and excluding special items	11-13%	9.7%	6-8%
AFUDC equity	$138	$154	$185
Capital expenditures (2)(3)	$11,825	$10,481	$10,475
Weighted-average shares outstanding – basic	~737 million	737 million	~769 million

2021 Interest Expense Assumption
(Consolidated Total $2,300)



2020 Interest Expense
(Consolidated Total $2,162)



(1) *Adjusted net income for 2021 assumptions is based upon the midpoint of the adjusted EPS guidance range of $5.00 to $5.30*
(2) *Includes debt AFUDC and capitalized interest*
(3) *2020 actual includes coal ash closure spend of ~$530 million that was included in operating cash flows and excludes tax equity funding of Commercial Renewables projects of ~$430 million. 2021 Assumptions include ~$550 million of projected coal ash closure spend.*

Electric utilities quarterly weather impacts

Weather segment income to normal:	2020			2019		
	Pretax impact	Weighted avg. shares	EPS impact favorable / (unfavorable)	Pretax impact	Weighted avg. shares	EPS impact favorable / (unfavorable)
First Quarter	($110)	734	($0.11)	($55)	727	($0.06)
Second Quarter	($8)	735	($0.01)	$80	728	$0.08
Third Quarter	$67	735	$0.07	$145	729	$0.15
Fourth Quarter	$2	742	--	$30	731	$0.03
Year-to-Date[(1)]	($48)	737	($0.05)	$200	729	$0.20

4Q 2020	Duke Energy Carolinas		Duke Energy Progress		Duke Energy Florida		Duke Energy Indiana		Duke Energy Ohio/KY	
Heating degree days / Variance from normal	1,098	(12.1%)	933	(17.1%)	207	1.8%	1,822	(7.6%)	1,671	(9%)
Cooling degree days / Variance from normal	51	25.7%	91	50%	624	41%	19	9.1%	21	(4%)

4Q 2019	Duke Energy Carolinas		Duke Energy Progress		Duke Energy Florida		Duke Energy Indiana		Duke Energy Ohio/KY	
Heating degree days / Variance from normal	1,143	(8.9%)	1,000	(11.6%)	105	(46.8%)	1,991	1%	1,766	(4.1%)
Cooling degree days / Variance from normal	94	161.5%	118	109.7%	674	43%	37	135.9%	49	172.2%

(1) Year-to-date amounts may not foot due to differences in weighted-average shares outstanding and/or rounding.

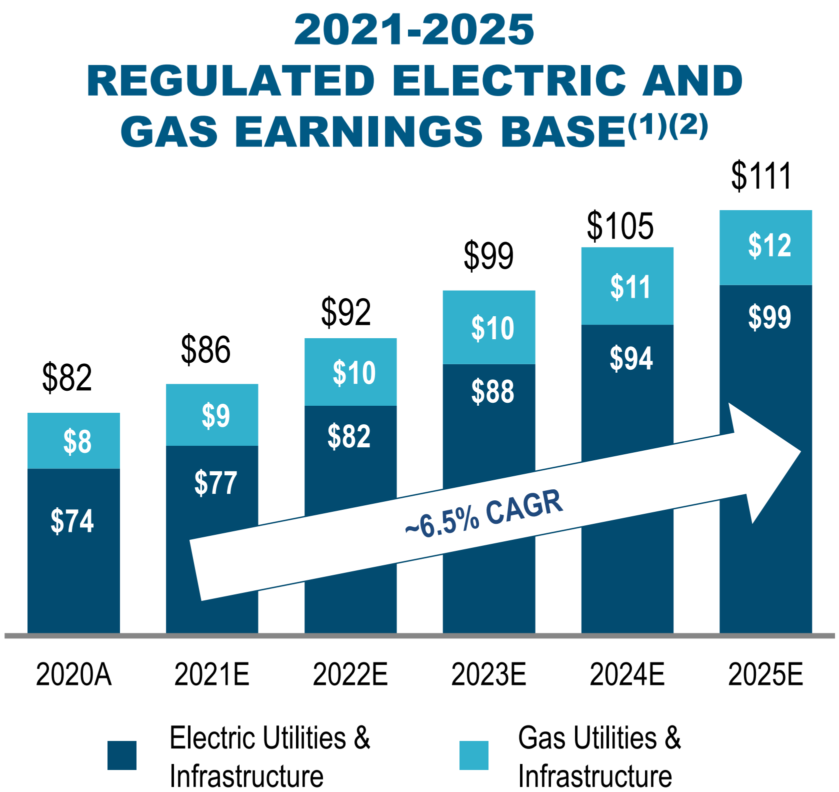
Key 2021 earnings sensitivities

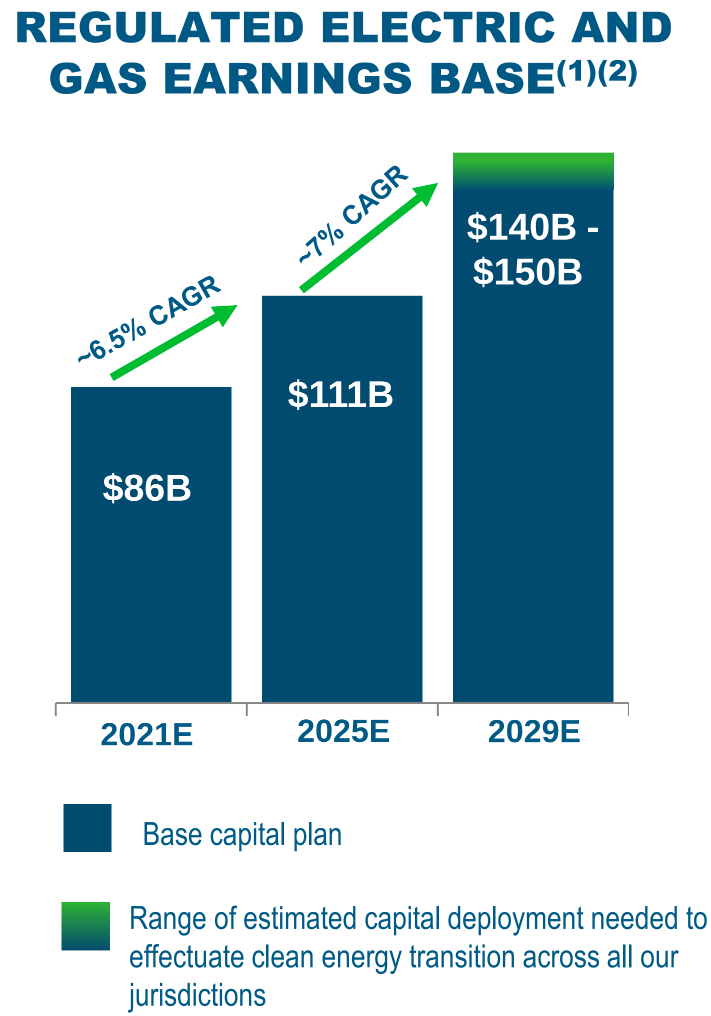
Driver		EPS Impact
Electric Utilities & Infrastructure	1% change in earned return on equity	+/- $0.55
	$1 billion change in rate base	+/- $0.06
	1% change in retail volumes: Industrial +/- $0.02 [(2)] Commercial +/- $0.05 [(2)] Residential +/- $0.08 [(2)]	+/- $0.15[(1) (2)]
Gas Utilities & Infrastructure	1% change in earned return on equity	+/- $0.05
	$200 million change in rate base	+/- $0.01
	1% change in number of new customers	+/- $0.02
Consolidated	1% change in interest rates[(3)]	+/- $0.10

Note: EPS amounts based on forecasted 2021 basic share count of ~769 million shares

(1) Assumes 1% change across all customer classes; EPS impact for the industrial class is lower due to lower margins
(2) Margin sensitivities are mitigated by the fixed component portion of bills, resulting in lower impacts to earnings than depicted.
(3) Based on average variable-rate debt outstanding throughout the year. There was $7.6 billion in floating rate debt as of December 31. 2020.

Earnings base growth





(1) In billions. Illustrative earnings base for presentation purposes only and includes retail and wholesale; Amounts as of the end of each year shown; Projected earnings base = prior period earnings base + capex – D&A – deferred taxes. Totals may not foot due to rounding

(2) Amounts presented gross of GIC 19.9% minority investment and earnings base is presented net of coal ash settlement.

Regulated utilities end of year earnings base[1]

Electric Utilities Earnings Base

($ in billions)	2020A	2021E	2022E	2023E	2024E	2025E
Duke Energy Carolinas[2]	$26.4	$27.9	$30.7	$33.3	$35.0	$37.2
Duke Energy Progress[2]	18.2	18.1	19.1	20.5	21.9	23.2
Duke Energy Florida	15.5	16.7	18.1	19.5	21.1	22.4
Duke Indiana	9.1	9.4	9.7	9.9	10.5	11.0
Duke Ohio – Electric	3.3	3.5	3.7	3.8	4.0	4.2
Duke Kentucky – Electric	1.1	1.2	1.3	1.3	1.4	1.4
Electric Utilities Total[3][4]	**$73.6**	**$76.8**	**$82.5**	**$88.3**	**$93.9**	**$99.5**

Gas Utilities Earnings Base

($ in billions)	2020A	2021E	2022E	2023E	2024E	2025E
Piedmont	$5.8	$6.4	$7.1	$7.7	$8.1	$8.6
Duke Energy Ohio – Gas	1.6	1.8	1.9	2.1	2.2	2.2
Duke Energy Kentucky - Gas	0.5	0.5	0.6	0.6	0.7	0.7
Gas Utilities Total[3]	**$7.9**	**$8.7**	**$9.6**	**$10.4**	**$11.0**	**$11.5**

($ in billions)	2020A	2021E	2022E	2023E	2024E	2025E
Total Company[3][4]	**$81.5**	**$85.5**	**$92.0**	**$98.7**	**$104.8**	**$111.0**

(1) Illustrative earnings base for presentation purposes only and includes retail and wholesale; Amounts as of the end of each year shown; Projected earnings base = prior period earnings base + capex – D&A – deferred taxes
(2) Amounts presented are net of 2021 North Carolina coal ash settlement
(3) Totals may not foot due to rounding
(4) Amounts presented gross of GIC 19.9% minority investment (~11% as of Q2 2021; 19.9% as of Jan. 2023)

Capital expenditures profile[1]

($ in millions)

Capital Expenditures	2020A	2021E	2022E	2023E	2024E	2025E	2021 - 2025
Electric Generation[2]	1,254	1,425	1,400	1,425	1,675	2,025	7,950
Electric Transmission	908	1,325	1,425	1,400	1,275	1,275	6,700
Electric Distribution	2,365	2,700	4,150	4,000	3,975	4,175	19,000
Environmental & Other[3]	693	800	825	600	450	400	3,075
Electric Utilities & Infrastructure Growth Capital	**$ 5,220**	**$ 6,250**	**$ 7,800**	**$ 7,425**	**$ 7,375**	**$ 7,875**	**$ 36,725**
Maintenance	2,936	2,200	2,650	2,750	2,700	2,475	12,775
Total Electric Utilities & Infrastructure Capital[4]	**$ 8,156**	**$ 8,450**	**$ 10,450**	**$ 10,175**	**$ 10,075**	**$ 10,350**	**$ 49,500**
Commercial Renewables[5]	759	425	800	475	400	400	2,500
Total Commercial Renewables Capital	**$ 759**	**$ 425**	**$ 800**	**$ 475**	**$ 400**	**$ 400**	**$ 2,500**
Renewable Natural Gas	-	100	-	-	-	-	100
LDC - Non-Rider	253	425	425	475	375	325	2,025
LDC - Rider	270	375	500	400	350	375	2,000
Gas Utilities & Infrastructure Growth Capital	**$ 523**	**$ 900**	**$ 925**	**$ 875**	**$ 725**	**$ 700**	**$ 4,125**
Maintenance	781	350	350	275	275	300	1,550
Total Gas Utilities & Infrastructure Capital	**$ 1,304**	**$ 1,250**	**$ 1,275**	**$ 1,150**	**$ 1,000**	**$ 1,000**	**$ 5,675**
Other[6]	263	350	275	275	275	200	1,375
Total Duke Energy	**$ 10,481**	**$ 10,475**	**$ 12,800**	**$ 12,075**	**$ 11,750**	**$ 11,950**	**$ 59,050**

(1) Amounts include AFUDC debt or capitalized interest. Totals may not foot due to rounding
(2) Includes nuclear fuel of ~$2.1B from 2021-2025
(3) 2020 actual amounts include ~$530 million in coal ash closure spending that was included in operating cash flows
(4) Capex amounts are presented gross of GIC minority investment (~11% as of Q2 2021; 19.9% as of Jan. 2023)
(5) Amounts are net of assumed tax equity financings
(6) Primarily IT and real estate related costs

Capital expenditures by utility (continued)[1]

($ in millions)

Duke Energy Carolinas	2020A	2021E	2022E	2023E	2024E	2025E	2021 - 2025
Electric Generation	612	500	550	575	575	725	2,925
Electric Transmission	99	300	400	475	225	150	1,550
Electric Distribution	762	1,050	1,850	1,700	1,400	1,550	7,550
Environmental & Other[2]	276	425	450	275	225	200	1,575
Electric Utilities & Infrastructure Growth Capital	**$ 1,749**	**$ 2,275**	**$ 3,250**	**$ 3,025**	**$ 2,425**	**$ 2,625**	**$ 13,600**
Maintenance	1,083	650	875	900	825	1,000	4,250
Total Duke Energy Carolinas	**$ 2,831**	**$ 2,925**	**$ 4,125**	**$ 3,925**	**$ 3,250**	**$ 3,625**	**$ 17,850**

Duke Energy Progress	2020A	2021E	2022E	2023E	2024E	2025E	2021 - 2025
Electric Generation	207	250	300	300	525	725	2,100
Electric Transmission	53	125	150	150	225	325	975
Electric Distribution	559	650	1,075	950	950	1,025	4,650
Environmental & Other[3]	319	200	225	200	150	150	925
Electric Utilities & Infrastructure Growth Capital	**$ 1,138**	**$ 1,225**	**$ 1,750**	**$ 1,600**	**$ 1,850**	**$ 2,225**	**$ 8,650**
Maintenance	744	650	825	850	700	450	3,475
Total Duke Energy Progress	**$ 1,882**	**$ 1,875**	**$ 2,575**	**$ 2,450**	**$ 2,550**	**$ 2,675**	**$ 12,125**

(1) Amounts include AFUDC debt. Totals may not foot due to rounding
(2) 2020 actual amounts include ~$162 million in coal ash closure spending that was included in operating cash flows
(3) 2020 actual amounts include ~$301 million in coal ash closure spending that was included in operating cash flows

Capital expenditures by utility (continued)[1]

($ in millions)

Duke Energy Florida		2020A		2021E		2022E		2023E		2024E		2025E		2021 - 2025
Electric Generation		324		600		450		400		300		275		2,025
Electric Transmission		465		550		600		550		500		475		2,675
Electric Distribution		497		525		700		800		1,025		950		4,000
Environmental & Other[2]		4		-		-		-		-		-		-
Electric Utilities & Infrastructure Growth Capital	**$**	**1,289**	**$**	**1,675**	**$**	**1,750**	**$**	**1,750**	**$**	**1,825**	**$**	**1,700**	**$**	**8,700**
Maintenance		619		475		500		575		750		600		2,900
Total Duke Energy Florida	**$**	**1,908**	**$**	**2,150**	**$**	**2,250**	**$**	**2,325**	**$**	**2,575**	**$**	**2,300**	**$**	**11,600**

Duke Energy Indiana		2020A		2021E		2022E		2023E		2024E		2025E		2021 - 2025
Electric Generation		111		75		25		150		300		300		850
Electric Transmission		119		200		150		100		175		175		800
Electric Distribution		239		250		225		250		275		300		1,300
Environmental & Other[3]		91		150		150		100		75		75		550
Electric Utilities & Infrastructure Growth Capital	**$**	**560**	**$**	**675**	**$**	**550**	**$**	**600**	**$**	**825**	**$**	**850**	**$**	**3,500**
Maintenance		389		325		350		325		325		300		1,625
Total Duke Energy Indiana[4]	**$**	**949**	**$**	**1,000**	**$**	**900**	**$**	**925**	**$**	**1,150**	**$**	**1,150**	**$**	**5,125**

(1) *Amounts include AFUDC debt. Totals may not foot due to rounding*
(2) *2020 actual amounts include ~$1 million in coal ash closure spending that was included in operating cash flows*
(3) *2020 actual amounts include ~$61 million in coal ash closure spending that was included in operating cash flows*
(4) *DEI capex presented gross of GIC minority investment (~11% as of Q2 2021; 19.9% as of Jan. 2023)*

Capital expenditures by utility (continued)[1]

($ in millions)

Duke Energy OH/KY Electric	2020A	2021E	2022E	2023E	2024E	2025E	2021 - 2025
Electric Generation	0	25	75	-	-	-	100
Electric Transmission	172	125	125	150	150	150	700
Electric Distribution	272	250	250	225	250	250	1,225
Environmental & Other[2]	4	-	-	-	-	-	-
Electric Utilities & Infrastructure Growth Capital	**$ 448**	**$ 400**	**$ 450**	**$ 375**	**$ 400**	**$ 400**	**$ 2,025**
Maintenance	102	100	100	100	100	125	525
Total DEO/DEK Electric	**$ 550**	**$ 500**	**$ 550**	**$ 475**	**$ 500**	**$ 525**	**$ 2,550**

Duke Energy OH/KY Gas	2020A	2021E	2022E	2023E	2024E	2025E	2021 - 2025
LDC - Non-Rider	56	150	100	125	125	125	625
LDC - Rider	-	25	-	-	-	-	25
Gas Utilities & Infrastructure Growth Capital	**$ 56**	**$ 175**	**$ 100**	**$ 125**	**$ 125**	**$ 125**	**$ 650**
Maintenance	230	175	200	175	150	100	800
Total DEO/DEK Gas	**$ 286**	**$ 350**	**$ 300**	**$ 300**	**$ 275**	**$ 225**	**$ 1,450**

Piedmont	2020A	2021E	2022E	2023E	2024E	2025E	2021 - 2025
LDC - Non-Rider	197	275	325	350	250	200	1,400
LDC - Rider	270	350	500	400	350	375	1,975
Gas Utilities & Infrastructure Growth Capital	**$ 467**	**$ 625**	**$ 825**	**$ 750**	**$ 600**	**$ 575**	**$ 3,375**
Maintenance	433	175	150	100	125	200	750
Total Piedmont Gas	**$ 900**	**$ 800**	**$ 975**	**$ 850**	**$ 725**	**$ 775**	**$ 4,125**

(1) Amounts include AFUDC debt. Totals may not foot due to rounding
(2) 2020 actual amounts include ~$2 million in coal ash closure spending that was included in operating cash flows

Carolinas coal ash costs

DEC and DEP system-wide estimated coal ash closure costs:

	Total Project Costs	Spend To Date (through 12/31/20)	2021 – 2025 Expected Spend	2026 – 2030 Expected Spend	Reg Asset Balance 12/31/2020
Duke Energy Carolinas	$4,365	$1,396	$1,060	$850	$570
Duke Energy Progress	$3,520	$1,391	$915	$530	$300
Total	**$7,885**	**$2,787**	**$1,975**	**$1,380**	**$870**

Note: estimated spend post-2030 expected to be ~$200M per year and declining over multiple decades

Summary of NC retail amortization period, allowed return, and revenue requirements per 2021 NC Coal Ash Settlement:

			Annualized revenue requirement/ (rates effective)	
	Amortization period	Allowed return during amortization period	DEC - NC	DEP - NC
2017 rate case costs	5 years	full WACC	$120M (8/1/2018)	$50M (3/15/2018)
2019 rate case costs	5 years	debt return + reduced ROE (-150 bps)	$40M adjusted request[1]	$47M adjusted request[1]
Future costs through 2030	to be determined by NCUC in future rate case proceedings	debt return + reduced ROE (-150 bps)	TBD	TBD

Note: Revenue requirements in chart above reflect NC retail only. Excludes ~$20M annualized collections from SC retail customers (effective 6/1/2019) and annual wholesale recoveries that average ~$150M 2018-2020[2].

(1) Revenue requirement requests as adjusted for 2021 NC Coal Ash Settlement.
(2) 2021 wholesale collections expected to be lower due to decreasing spend as well as refund of prior collections resulting from 2021 Coal Ash Settlement

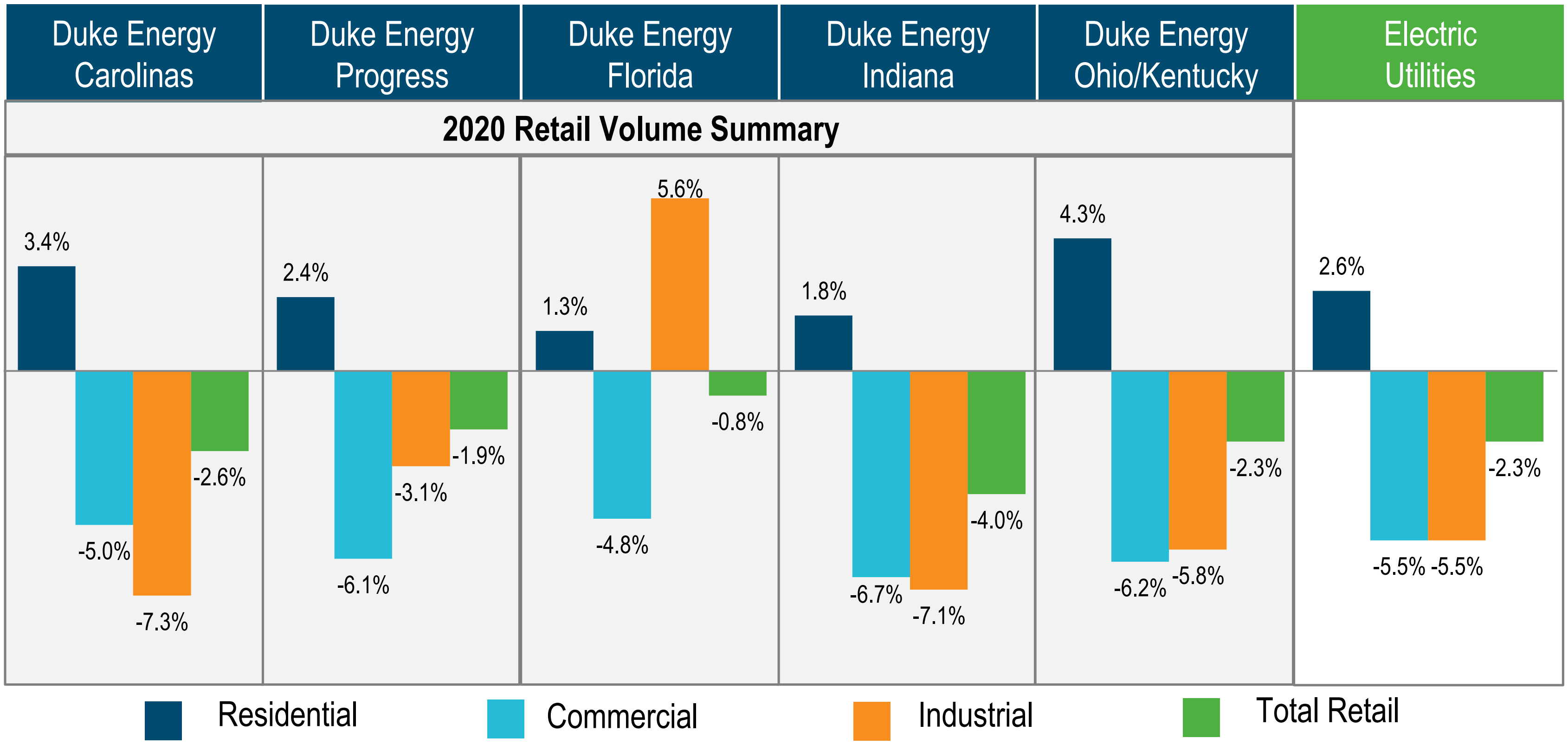
Environmental compliance expenditures

($ in millions)

Coal Ash Closure Costs	Total Project Costs	Spend To Date[1]	2021-2025 Plan
Duke Energy Carolinas	$4,365	$1,396	$1,060
Duke Energy Progress	$3,520	$1,391	$915
Duke Energy Indiana	$1,350	$334	$530
Duke Energy Florida	$40	$5	$ --
Duke Energy Kentucky	$115	$28	$20
Total	**$9,390**	**$3,154**	**$2,525**

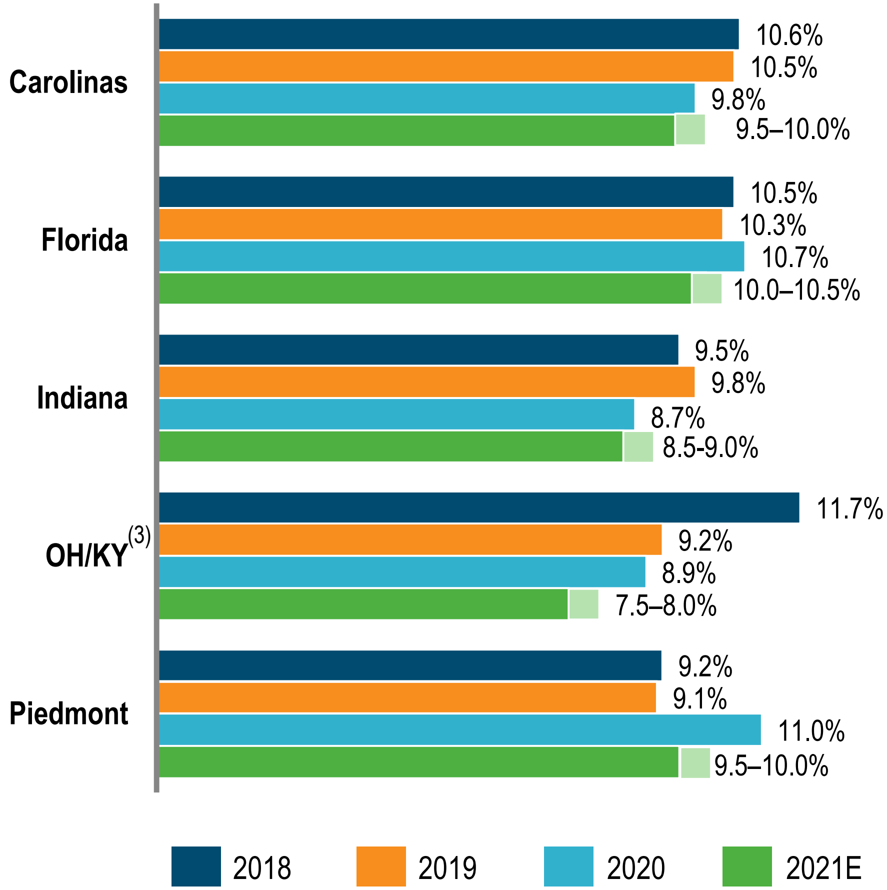
(1) As of Dec. 31, 2020

Weather normalized volume trends, by electric jurisdiction

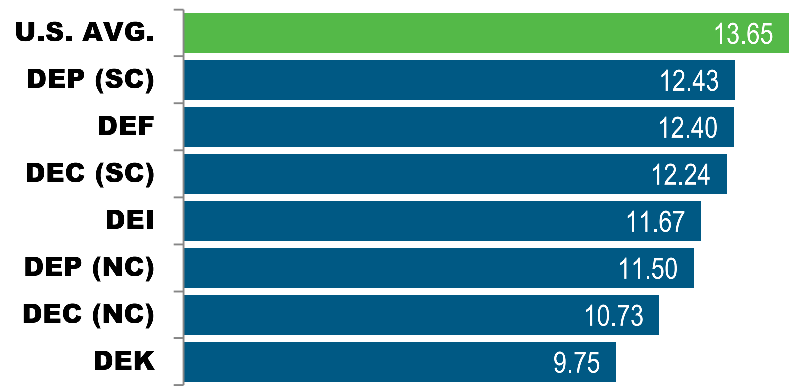


Managing regulatory lag and customer rate impacts

ADJUSTED BOOK ROEs[1]



COMPETITIVE CUSTOMER RATES[2]



DELIVERING COMPETITIVE RETURNS FOR INVESTORS WHILE KEEPING RATES WELL BELOW THE NATIONAL AVERAGE FOR CUSTOMERS

(1) Adjusted book ROEs exclude special items and are based on average book equity less Goodwill. Adjusted ROEs also include wholesale and are not adjusted for the impacts of weather. Regulatory ROEs will differ from Adjusted Book ROEs

(2) Residential customer rates. Typical bill rates (¢/kWh) in effect as of January 1, 2020. Vertically integrated utilities only. Source: EEI Typical Bills and Avg. Rates Report, Winter 2020

(3) Combined electric and gas utilities

Financing plan update and current liquidity

2021 Financing plan(1)

Issuer	Estimated / Actual Amount ($ in millions)	Security	Completed ($ in millions)	Date Issued	Term	Rate	2021 Maturities(2)
Holding Company	$2,750 – $3,250	-	-	-	-	-	$1,750 (May & Sept)
DE Carolinas	$900 - $1,100	-	-	-	-	-	$500 (June)
DE Progress	$1,000 - $1,200	-	-	-	-	-	$1,300 (June & Sept.)
DE Florida	$1,100 - $1,300	-	-	-	-	-	$500 (Aug. & Nov.)
DE Indiana	$300 - $400	-	-	-	-	-	-
Piedmont	$300 - $400	-	-	-	-	-	$160 (June)
DE Kentucky	$50 - $100	-	-	-	-	-	-
Total	**$6,400 - $7,750**	**-**	**-**	**-**	**-**	**-**	**$4,210**

(1) Excludes financings at Commercial Renewables and other non-regulated entities and storm cost securitization at Duke Energy Carolinas and Duke Energy Progress
(2) Excludes amortization of noncash purchase accounting adjustments and CR3 securitization

Liquidity summary (as of December 31, 2020)

($ in millions)

	Duke Energy	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio	Duke Energy Kentucky	Piedmont Natural Gas	Total
Master Credit Facility [1]	$ 2,650	$ 1,475	$ 1,250	$ 800	$ 600	$ 450	$ 175	$ 600	$ 8,000
Less: Notes payable and commercial paper [2]	212	(806)	(445)	(196)	(281)	(93)	(100)	(530)	(2,239)
Outstanding letters of credit (LOCs)	(34)	(4)	(2)	-	-	-	-	-	(40)
Tax-exempt bonds	-	-	-	-	(81)	-	-	-	(81)
Available capacity	$ 2,828	$ 665	$ 803	$ 604	$ 238	$ 357	$ 75	$ 70	$ 5,640
Funded Revolver and Term Loan [3]	$ 1,000								$ 1,000
Less: Borrowings Under Credit Facilities	(500)								(500)
Available capacity	$ 500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 500
Cash & short-term investments									208
Total available liquidity									**$ 6,348**

(1) Duke Energy's master credit facility supports Tax-Exempt Bonds, LOCs and the Duke Energy CP program of $6 billion.
(2) Includes permanent layer of commercial paper of $625 million, which is classified as long-term debt
(3) Borrowings under these facilities will be used for general corporate purposes.

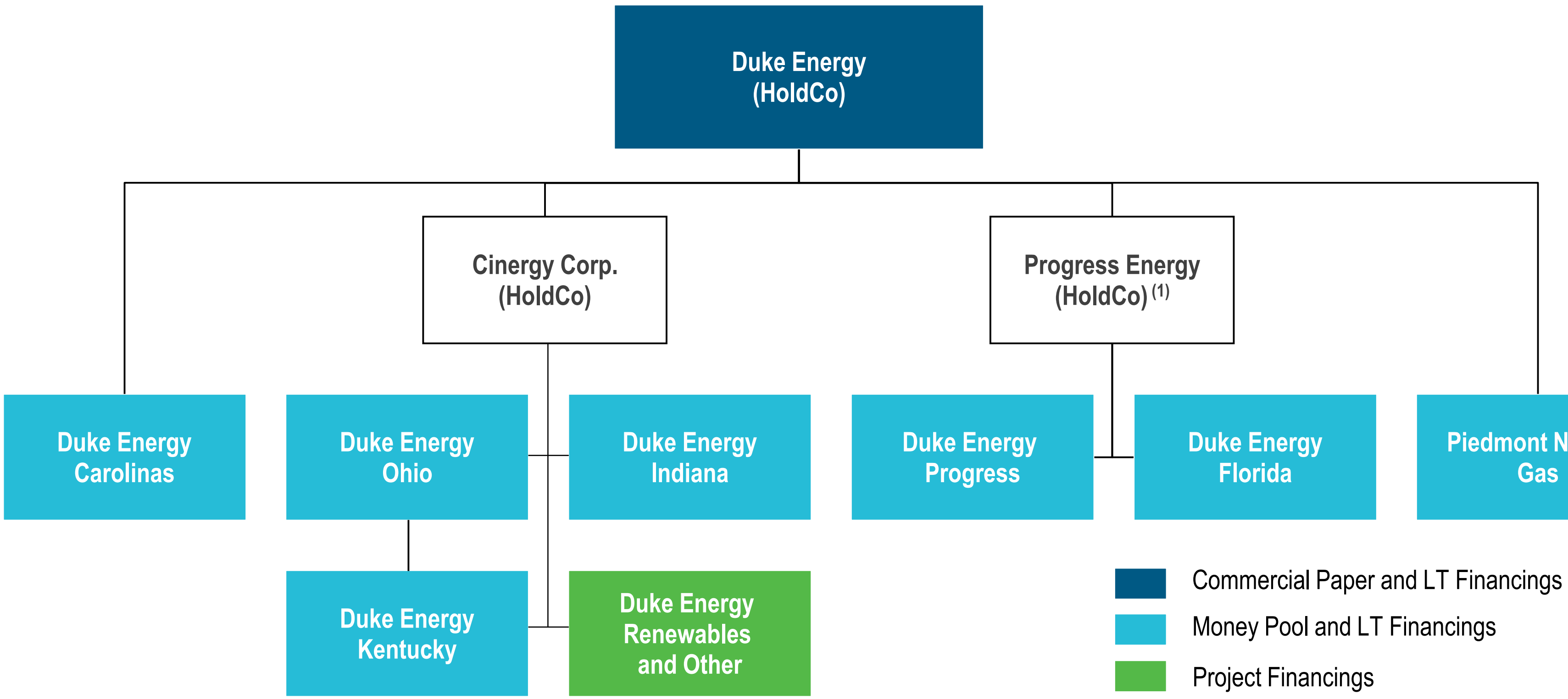
2021 Pension funding and costs

- On a consolidated basis, Duke Energy pension plans are fully funded as of 12/31/2020 on a PBO basis
- Duke Energy's pension funding policy:
  - Duke Energy's policy is to fund amounts on an actuarial basis to provide assets sufficient to meet benefit payments to be paid to plan participants
  - Duke plans have a targeted allocation of 58% fixed-income assets and 42% return-seeking assets

Pension Contributions *($ in millions)*	2019A	2020A	2021E – 2025E
All plans	$77	$0	$0

- Key 2021 assumptions:
  - Discount rate: 2.6% for 2021 (vs. 3.3% for 2020)
  - Expected long-term return of 6.50% on plan assets (decrease from 2020's 6.85% assumption)
  - Pension plan fully funded (no expected contributions in 5-year plan)

Simplified financing structure



(1) Progress Energy HoldCo has long-term debt outstanding, but no future common equity issuance is planned at this financing entity

Credit ratings (as of February 11, 2021) and 2020 cash flow metrics(1)

Current Ratings	Moody's	S&P
DUKE ENERGY CORPORATION	Negative	Stable
Senior Unsecured Debt	Baa1	BBB
Commercial Paper	P-2	A-2
PROGRESS ENERGY, INC	Stable	Stable
Senior Unsecured Debt	Baa1	BBB
DUKE ENERGY CAROLINAS	Negative	Stable
Senior Secured Debt	Aa2	A
Senior Unsecured Debt	A1	BBB+
DUKE ENERGY PROGRESS	Negative	Stable
Senior Secured Debt	Aa3	A
Senior Unsecured Debt	A2	BBB+
DUKE ENERGY FLORIDA	Stable	Stable
Senior Secured Debt	A1	A
Senior Unsecured Debt	A3	BBB+
DUKE ENERGY INDIANA	Stable	Stable
Senior Secured Debt	Aa3	A
Senior Unsecured Debt	A2	BBB+
DUKE ENERGY OHIO	Stable	Stable
Senior Secured Debt	A2	A
Senior Unsecured Debt	Baa1	BBB+
DUKE ENERGY KENTUCKY	Stable	Stable
Senior Unsecured Debt	Baa1	BBB+
PIEDMONT NATURAL GAS	Stable	Stable
Senior Unsecured Debt	A3	BBB+

	Duke Energy Corporation
Holdco Debt/Total Debt	33%
FFO/Debt (2)(3)	15%

	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida
FFO/Debt(2)(3)	21%	18%	23%

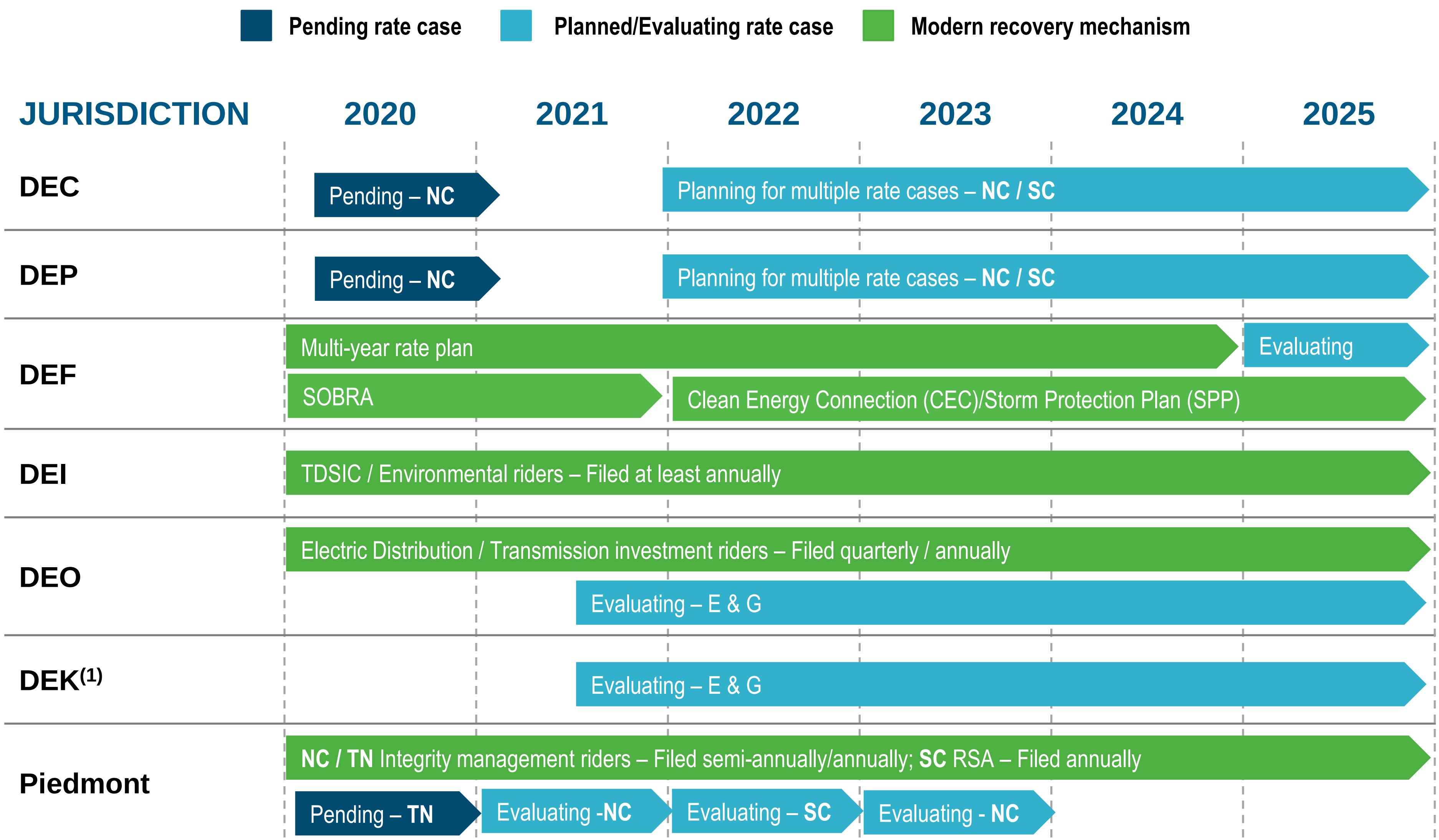
	Duke Energy Indiana	Duke Energy Ohio Cons.	Piedmont
FFO/Debt(2)(3)	21%	15%	13%

Simplified 2021 Cash Flows	
Adjusted net income(4)	$ 3,960
Depreciation & amortization	5,655
Deferred and accrued taxes	325
Other sources / (uses), net(5)	600
Primary sources	**10,540**
Capital expenditures	(10,475)
Dividends (subject to Board of Directors discretion)	(3,000)
Primary uses	**(13,475)**
Uses in excess of sources	(2,935)
Net Change in debt	2,940
Net Change in Cash	**$ 5**

(1) Amounts do not include all adjustments that may be made by the rating agencies
(2) Key adjustments within the computation include the removal of coal ash remediation spending from FFO, and the adjusted debt balance excludes purchase accounting adjustments
(3) Assumes securitization treated as off credit
(4) Based upon the midpoint of the 2021 guidance range
(5) Includes ~$1B of proceeds from the first closing of the Duke Energy Indiana minority stake sale as well as changes in working capital and AFUDC equity

Regulatory overview

Regulatory calendar



(1) "E" denotes Electric, "G" denotes Gas

Overview of state commissions by jurisdiction

	North Carolina	South Carolina	Florida	Indiana	Ohio	Kentucky	Tennessee
Number of Commissioners	7	7	5	5	5	3	5
Term (years)	6	4	4	4	5	4	6
Appointed/Elected	Appointed by Governor	Elected by the General Assembly	Appointed by Governor	Appointed by Governor	Appointed by Governor	Appointed by Governor	Appointed by Governor and Legislature
Chair *(Term Exp.)*	Charlotte Mitchell *(June 2023)*	Justin Williams (June 2022)	Gary Clark (January 2023)	Jim Huston (March 2021)	[OPEN]	Michael Schmitt (June 2023)	Robin Morrison (June 2026)(1)
Other Commissioners *(Term Exp.)*	▪ Lyons Gray (June 2021) ▪ ToNola Brown-Bland (June 2023) ▪ Dan Clodfelter (June 2023) ▪ Floyd McKissick (June 2025) ▪ Kimberly Duffley (June 2025) ▪ Jeff Hughes (June 2025)	▪ Tom Ervin (June 2022) ▪ Florence Belser (February 2023) ▪ Mike Caston (June 2024) ▪ Headen Thomas (June 2024) ▪ Carolee Williams (June 2024) ▪ Delton Powers (June 2024)	▪ Art Graham (January 2022) ▪ Andrew Fay (January 2022) ▪ Julie Brown (January 2023) ▪ Mike La Rosa (January 2025)	▪ Sarah Freeman (January 2022) ▪ Stefanie Krevda (April 2022) ▪ David Ziegner (April 2023) ▪ David Ober (January 2024)	▪ Lawrence Friedeman (April 2020) ▪ Dennis Deters (April 2021) ▪ Daniel Conway (April 2022) ▪ Beth Trombold – acting chair (April 2023)	▪ Kent Chandler (June 2024) – senate confirmation pending ▪ Talina Mathews (June 2021)	▪ Kenneth Hill (June 2026)(1) ▪ Herbert Hilliard (June 2023) ▪ John Hie (June 2024) ▪ David Jones (June 2024)

(1) Pending confirmation by the Tennessee Legislature

Current electric rate information by jurisdiction

	North Carolina	South Carolina (1)	Florida	Indiana	Ohio (Electric)	Kentucky (Electric)
Retail Rate Base	$16.9 B (2) (DEC) $10.6 B (2) (DEP)	$5.4 B (DEC) $1.5 B (DEP)	$14.7 B (3)	$9.9 B	$1.3 B (dist. only)	$881 M
Wholesale Rate Base	$2.1 B (DEC) 3Q 2020 $3.6 B (DEP) 3Q 2020		$2.1 B (3)	$579 M	$0.7 B (trans. only)	$0
Allowed ROE	9.6% (DEC & DEP)	9.5% (DEC & DEP)	10.50% (4)	9.7%	9.84% - Dist 11.38% - Trans	9.25%
Allowed Equity	52.0% (DEC & DEP)	53.0% (DEC & DEP)	42.03% (5)	41.05% (6)	50.8%	48.2%
Effective Date of Most Recent Rates	Interim Rates 8/24/20 (DEC) 9/1/20 (DEP)	6/1/19 (DEC & DEP)	1/1/21	7/30/20	Distr: 1/2/19 Trans 6/1/20 ESP: 1/2/19	5/1/20
Fuel Clause Updated	Annually (DEC & DEP)	Annually (DEC & DEP)	Annually	Quarterly	Annually for Non-Shoppers	Monthly
Environmental Clause Updated	N/A	N/A	Annually	Semi-Annually	Quarterly	Monthly

(1) DEC SC and DEP SC rate base and allowed ROE as of June 2019. The Public Service Commission of South Carolina issued orders in the DEC SC and DEP SC rate cases on May 21, 2019. DEC and DEP filed notices of appeal on November 15, 2019.
(2) DEC NC's rate base included in interim rates as of August 24, 2020. DEP NC's rate base included in interim rates as of September 1, 2020. Final rates will be implemented after the NCUC orders are issued in Q1 2021.
(3) Florida's thirteen-month average as of November 2020. Retail rate base includes amounts recovered in base rates of $14.2B and amounts recovered in trackers of $0.5B.
(4) Represents the mid-point of an authorized range from 9.5% to 11.5%.
(5) Florida's capital structure includes accumulated deferred income taxes (ADIT), customer deposits and investment tax credits (ITC) and is as of Nov. 30, 2020. Excluding these items, the capital structure approximates 51% equity.
(6) Indiana's capital structure includes ADIT. When ADIT is excluded, the capital structure approximates 53% equity as of September 30, 2020.

Current electric rate information by jurisdiction (continued)

General Rate Case Provisions

	North Carolina	South Carolina	Florida	Indiana	Ohio (Electric)	Kentucky (Electric)
Notice of Intent Required?	Yes	Yes	Yes	Yes (1)	Yes	Yes
Notice Period	30 Days	30 Days	60 Days	30 Days (2)	30 Days	30 Days
Test Year	Historical Adjusted for Known and Measureable Changes	Historical Adjusted for Known and Measureable Changes	Projected	Optional (3)	Partially Projected	Forecast Optional
Time Limitation Between Cases	No	12 months	No	15 Months	No	No
Rates Effective Subject to Refund	9 Months After Filing	6 Months After Filing (4)	8 Months After Filing	10 Months After Filing (5)	9 Months After Filing	6 Months After Filing (6)

(1) IURC recommended procedure. Not a statutory requirement
(2) As least 30 days to avoid ex parte issues
(3) Utilities may elect to a historical test period, a forward-looking test period, or a hybrid test year in the context of a general rate case
(4) If the South Carolina Commission fails to rule on a rate case filing within 6 months, the new rates can be implemented and are not subject to refund. There is a grace period here. The Company would have to notify the Commission that it planned to put rates in and the Commission would then have 10 additional days to issue an order
(5) The utility may implement interim rates, subject to refund, if the IURC has not rendered a decision within 10 months of filing (can be extended 60 days by IURC). The interim rates are not to exceed 50% of the original request
(6) The effective date is 7 months after filing for a forecasted test year

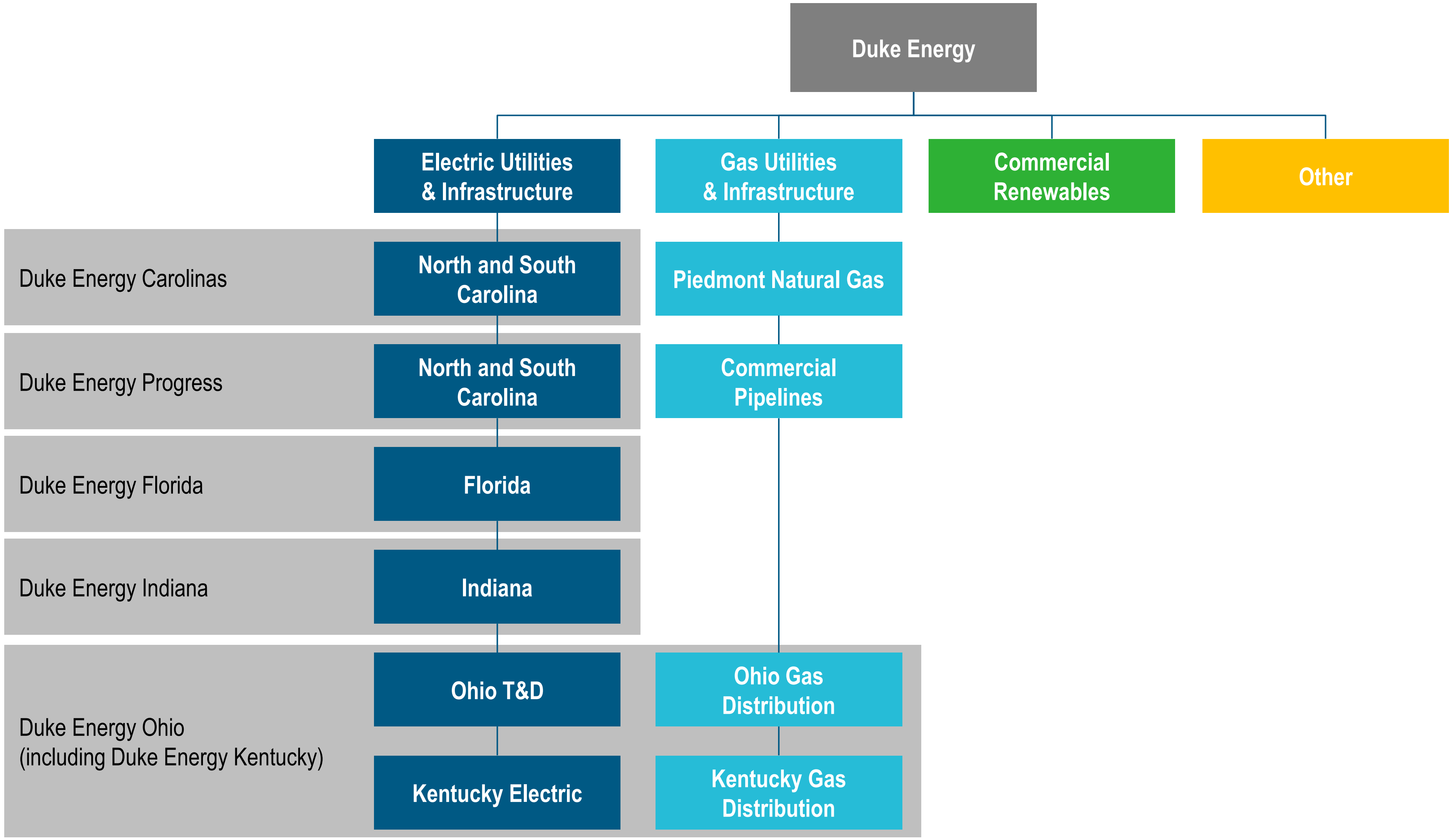
Current gas rate information by jurisdiction

	North Carolina	South Carolina	Tennessee[1]	Ohio (Gas)	Kentucky (Gas)
Rate Base ($M)	$3.5 billion	$366 million	$897 million	$900 million[2]	$313 million
Allowed ROE	9.7%	9.8%	9.8%	9.84%	9.7%
Allowed Equity	52%	52.31%	50.5%	53.3%	50.8%
Effective Date of Most Recent Rates	11/1/19	11/1/20 [3]	1/2/21	12/1/13	4/1/19
Significant Rider Mechanisms	Margin Decoupling Rider Integrity Management Rider Fuel Clause	Rate Stabilization Adj. Weather Normalization Adj. Fuel Clause	Weather Normalization Adj. Integrity Management Rider Fuel Clause	AMRP SmartGrid[4] Fuel Clause Capital Expenditure[5]	Weather Normalization Adj. Fuel Clause

(1) Reflects terms of settlement agreement with Tennessee Consumer Advocate. Currently pending commission approval.
(2) Excludes all rate base related to capital recovery that is being tracked (e.g., AMRP and AU after 3/31/2012)
(3) Rates refreshed annually under the South Carolina Rate Stabilization Act (RSA)
(4) The Ohio Commission temporarily suspended DEO's Gas SmartGrid Rider pending an audit.
(5) The Company has a pending application to implement a capital expenditure rider (Rider CEP) that will recover certain capital-related costs for incremental investment in most gas utility plant since the most recent base rate case approved in 2012.

Segment overviews

Duke Energy business segment structure



Duke Energy – a large scale, highly regulated energy infrastructure company

HEADQUARTERED IN CHARLOTTE, NC

DUK
LISTED
NYSE

A FORTUNE 150 COMPANY

$69 B
MARKET CAP
(AS OF 2/9/2021)

$162 B
TOTAL ASSETS
(AS OF 12/31/2020)

28 K
EMPLOYEES
(AS OF 12/31/2020)

54 GWs
TOTAL GENERATING CAPACITY (AS OF 12/31/2020)

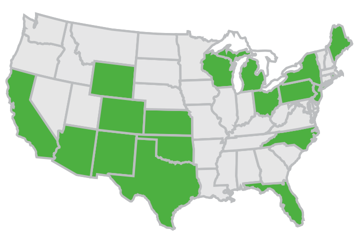
ELECTRIC UTILITIES & INFRASTRUCTURE

- Operating in six constructive jurisdictions, with attractive allowed ROEs, serving 7.9 million retail customers
- Customer rates below the national average(1)
- Balanced generation portfolio that has reduced its carbon emissions by over 40% since 2005(2)
- Industry-leading safety performance, as recognized by EEI

GAS UTILITIES & INFRASTRUCTURE

- Five state LDCs serving 1.6 million customers
- Strong earnings trajectory driven by customer growth, system integrity improvements, and continued expansion of natural gas infrastructure
- Efficient recovery mechanisms allow for timely recovery of investments

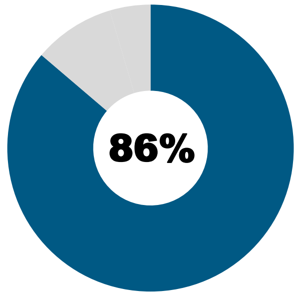
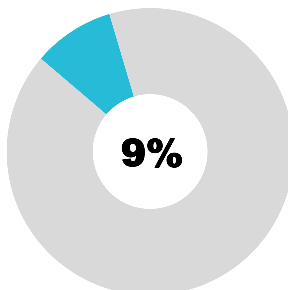
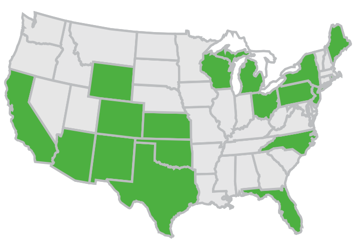
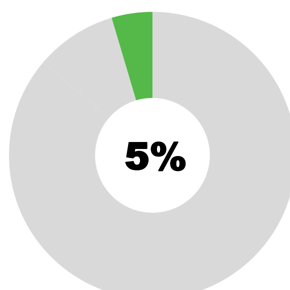
COMMERCIAL RENEWABLES



- Approximately 4 GWs of wind and solar in operation
- Long-term Power Purchase Agreements with creditworthy counterparties

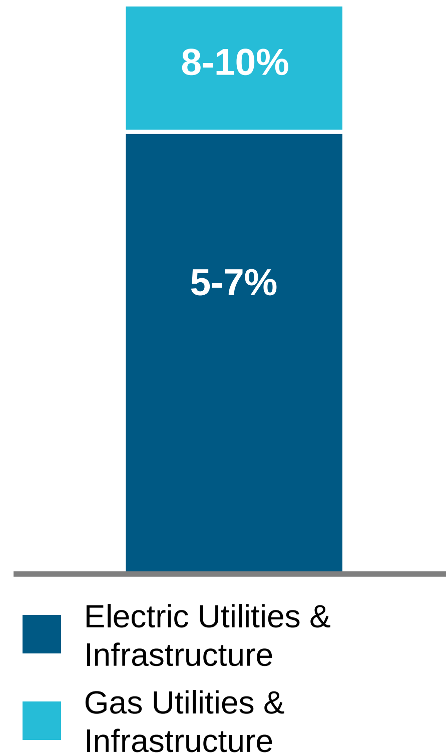
(1) Typical bill rates (¢/kWh) in effect as of January 1, 2020. Vertically integrated utilities only. Source: EEI Typical Bills and Avg. Rates Report, Winter 2020
(2) Year to year reductions will be influenced by customer demand for electricity, weather, fuel and purchased power costs and other factors.

Complementary businesses with strong growth opportunities

	2021 ADJUSTED **EPS CONTRIBUTION**[1]	2021-2025 **CAPEX**
ELECTRIC UTILITIES & INFRASTRUCTURE 	 86%	$49.5 B
GAS UTILITIES & INFRASTRUCTURE 	 9%	$5.7 B
COMMERCIAL RENEWABLES 	 5%	$2.5 B[3]

2021 – 2025 ADJUSTED EPS CAGR[2]

Consolidated 5-7%



(1) *Based upon the midpoint of the 2021 adjusted EPS guidance range of $5.00-$5.30 per share; excludes the impact of Other*
(2) *CAGR off of the components of the midpoint of the 2021 EPS guidance range of $5.00-$5.30 per share; consolidated growth rate includes the impact of Commercial Renewables (approximately flat growth) and Other*
(3) *Net of tax equity financing*

Electric utilities & infrastructure

EIGHT UTILITIES IN HIGH-QUALITY REGIONS OF THE U.S.

CAROLINAS

Duke Energy Carolinas (NC/SC)

Duke Energy Progress (NC/SC)

FLORIDA

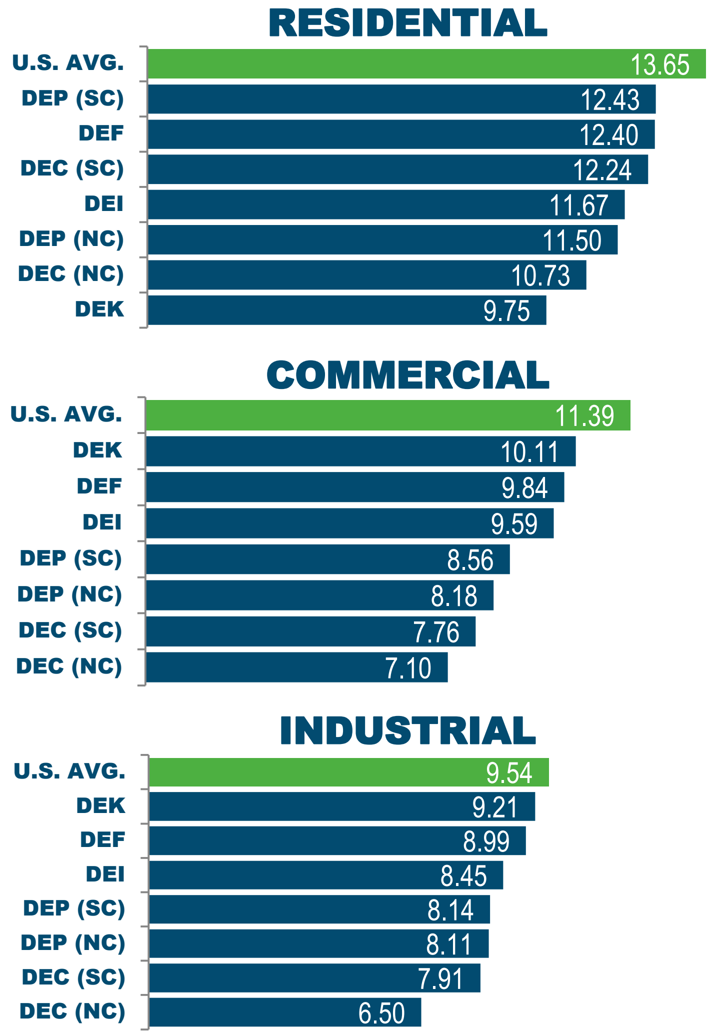
Duke Energy Florida

MIDWEST

Duke Energy Indiana

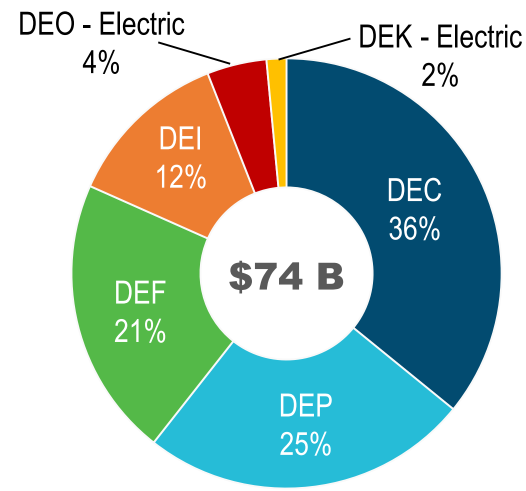
Duke Energy Ohio / Kentucky

COMPETITIVE CUSTOMER RATES(1)

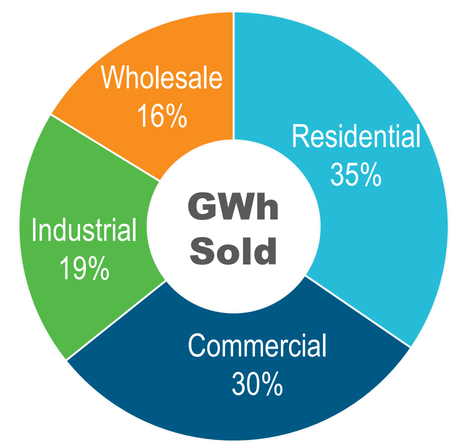


(1) *Typical bill rates (¢/kWh) in effect as of January 1, 2020. Vertically integrated utilities only. Source: EEI Typical Bills and Avg. Rates Report, Winter 2020. Certain adjustments made due to computation errors.*

REGULATED ELECTRIC 2020 EARNINGS BASE

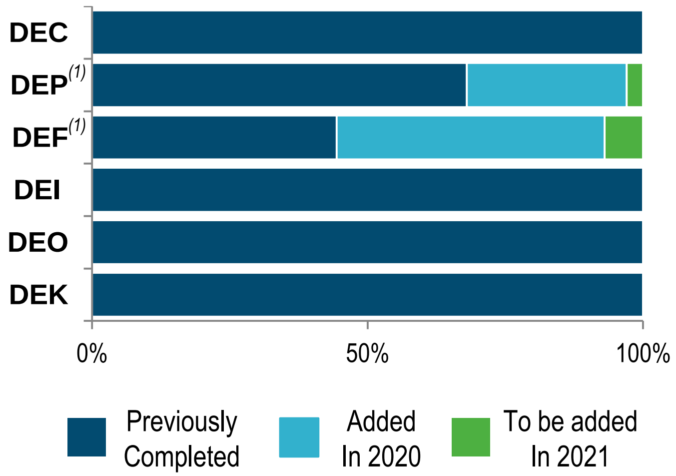


BALANCED CUSTOMER MIX



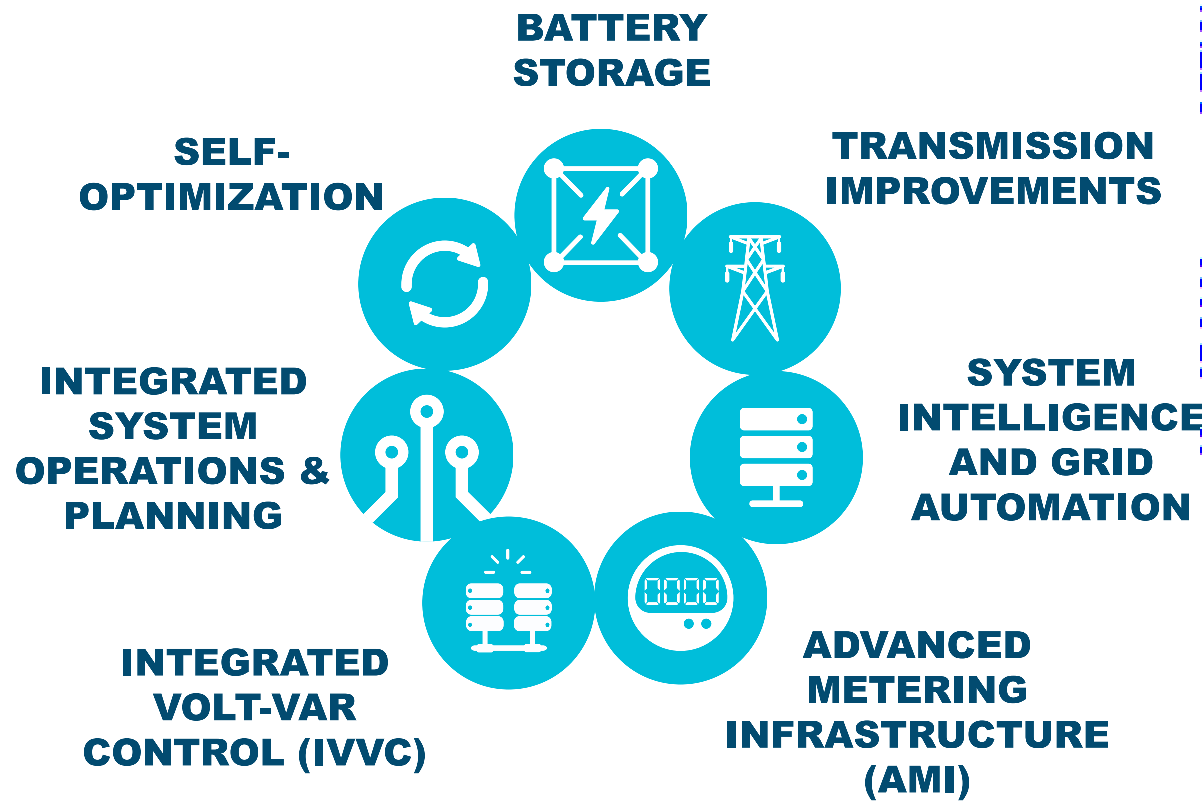
Grid improvement programs overview

AMI DEPLOYMENT



PRIMARY RECOVERY MECHANISMS

Carolinas	Deferral/Base rate cases
Florida	MYRP/SPP rider
Indiana	TDSIC rider
Ohio	DCI and BTR riders
Kentucky	Base rate cases



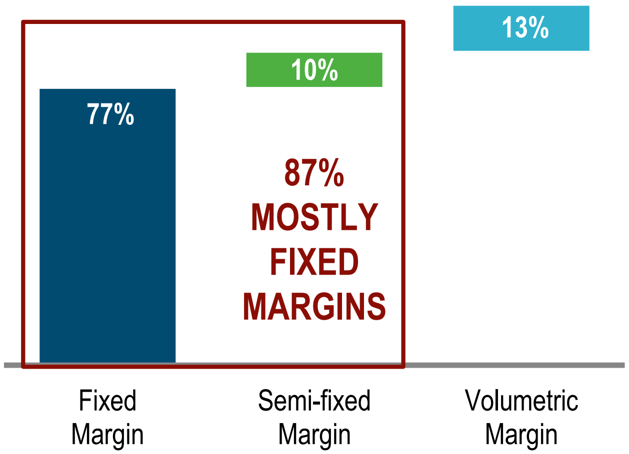
CUSTOMER BENEFITS

Improved resiliency	Enable EV charging and battery systems	Support innovative customer programs	Localized intelligent control systems

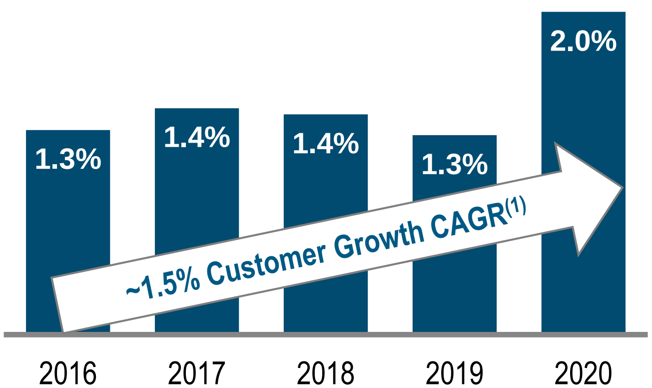
(1) *Remaining amounts expected to be completed in Q2 2021*

Gas utilities & infrastructure

GAS UTILITIES WITH LOW VOLUMETRIC EXPOSURE DUE TO **MOSTLY FIXED MARGINS…**



…WITH EARNINGS DRIVEN BY **INVESTMENT AND STRONG RESIDENTIAL CUSTOMER GROWTH**



(1) Piedmont CAGR: 1.8%, Midwest LDC CAGR 0.9%

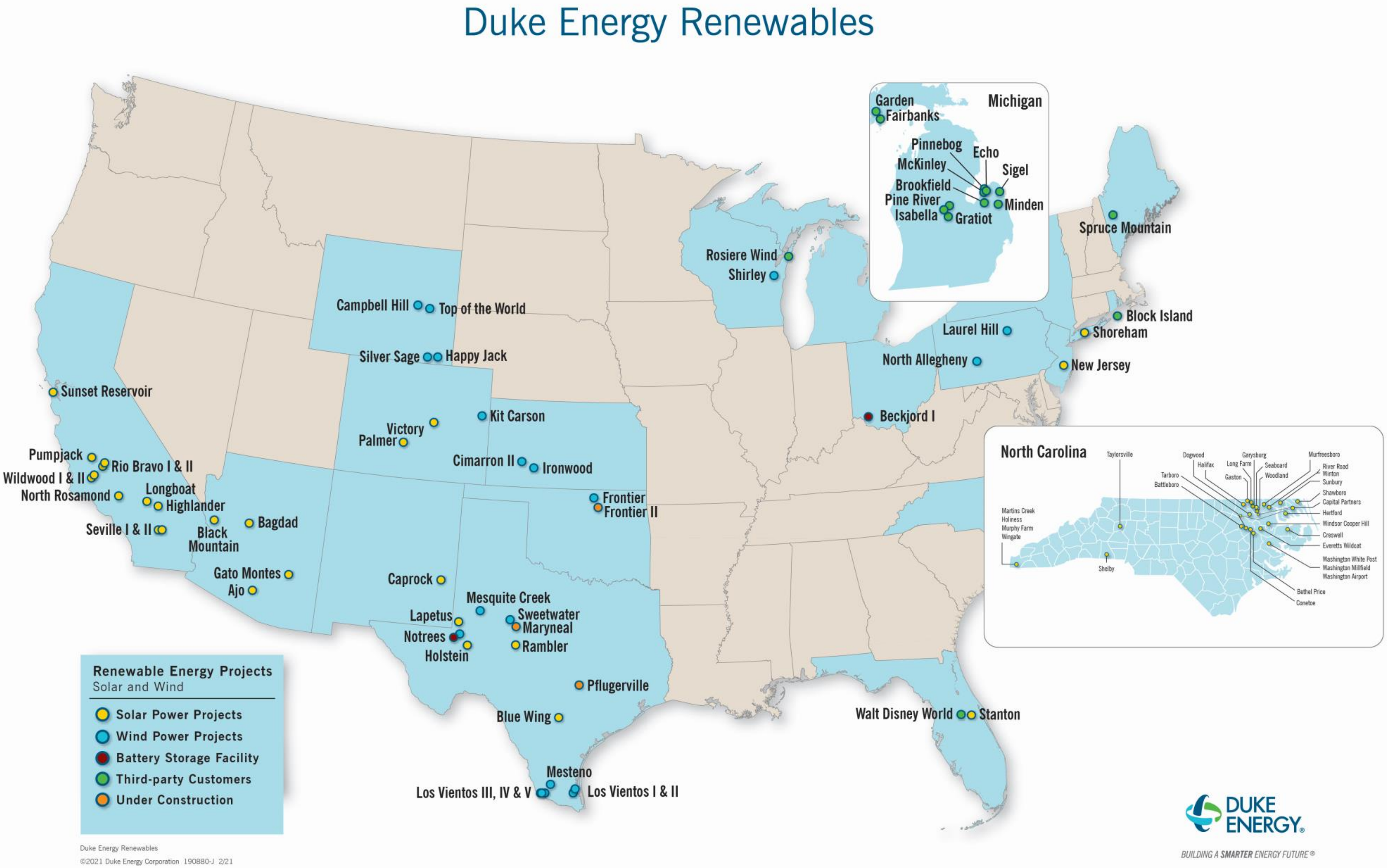
MARGIN STABILIZING MECHANISMS

1. Purchased Gas Adjustment	All States
2. Uncollectible Recovery	All States
3. Integrity Management Rider ("IMR")	North Carolina and Tennessee
4. Margin Decoupling	North Carolina
5. Weather Normalization	South Carolina, Tennessee and Kentucky
6. Rate Stabilization Act	South Carolina
7. Accelerated Main Replacement Program Rider	Ohio
8. Advanced Utility Rider	Ohio
9. Manufactured Gas Rider	Ohio
10. Fixed Customer Charge	All States

Commercial Renewables asset locations

A full list of generation facilities can be found at:

https://www.duke-energy.com//_/media/pdfs/our-company/investors/duke-energy-generation-portfolio.pdf



Upcoming events

Event	Date
1Q 2021 earnings call (tentative)	May 10, 2021
2Q 2021 earnings call (tentative)	August 5, 2021
3Q 2021 earnings call (tentative)	November 4, 2021

Investor relations contact information

JACK SULLIVAN, VICE PRESIDENT INVESTOR RELATIONS

- Jack.Sullivan@duke-energy.com
- (980) 373-3564

CINDY LEE, DIRECTOR INVESTOR RELATIONS

- Cynthia.Lee@duke-energy.com
- (980) 373-4077

ABBY MOTSINGER, MANAGER INVESTOR RELATIONS

- Abby.Motsinger@duke-energy.com
- (704) 382-7624

DUKE ENERGY®

BUILDING A **SMARTER** ENERGY FUTURE ®

For additional information on Duke Energy,
please visit: duke-energy.com/investors

Duke Energy Corporation
Non-GAAP Reconciliations
Fourth Quarter Earnings Review & Business Update
February 11, 2021

Adjusted Earnings per Share (EPS)

The materials for Duke Energy Corporation's (Duke Energy) Fourth Quarter Earnings Review and Business Update on February 11, 2021, include a discussion of adjusted EPS for the year-to-date periods ended December 31, 2020 and 2019.

The non-GAAP financial measure, adjusted EPS, represents basic EPS available to Duke Energy Corporation common stockholders (GAAP reported EPS), adjusted for the per share impact of special items. As discussed below, special items represent certain charges and credits, which management believes are not indicative of Duke Energy's ongoing performance.

Management believes the presentation of adjusted EPS provides useful information to investors, as it provides them with an additional relevant comparison of Duke Energy's performance across periods. Management uses this non-GAAP financial measure for planning and forecasting and for reporting financial results to the Duke Energy Board of Directors, employees, stockholders, analysts and investors. Adjusted EPS is also used as a basis for employee incentive bonuses. The most directly comparable GAAP measure for adjusted EPS is reported basic EPS available to Duke Energy Corporation common stockholders. Reconciliations of adjusted EPS for the year-to-date periods ended December 31, 2020 and 2019, to the most directly comparable GAAP measure are included herein.

Special items included in the periods presented include the following items, which management believes do not reflect ongoing costs:

- Gas Pipeline Investments represents costs related to the cancellation of the ACP pipeline and additional exit costs related to Constitution.
- Regulatory Settlements represents charges related to Duke Energy Carolinas and Duke Energy Progress coal ash settlement and the partial settlements in the 2019 North Carolina rate cases.
- Severance represents the reversal of 2018 costs, which were deferred as a result of a partial settlement in the Duke Energy Carolinas and the Duke Energy Progress 2019 North Carolina rate cases.
- Impairment Charges represents a reduction of a prior year impairment at Citrus County CC and an other-than-temporary impairment on the remaining investment in Constitution.

Adjusted EPS Guidance

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 11, 2021, include a reference to forecasted 2021 adjusted EPS guidance range of $5.00 to $5.30 per share. In addition, the materials reference a preliminary estimate of the 2021 adjusted EPS midpoint of approximately $5.15. The materials also include a reference to the midpoint of the original forecasted 2020 adjusted EPS guidance range of $5.25. In addition, the materials reference the long-term range of annual growth of 5% - 7% through 2025 off the midpoint of 2021 adjusted EPS guidance range of $5.15. The materials also reference the expected five-year EPS growth in the natural gas segment of 8-10% (on a compound annual growth rate (CAGR) basis). The forecasted adjusted EPS is a non-GAAP financial measure as it represents basic EPS available to Duke Energy Corporation common stockholders (GAAP reported EPS), adjusted for the per share impact of special items (as discussed above under Adjusted EPS).

Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items for future periods, such as legal settlements, the impact of regulatory orders or asset impairments.

Adjusted Segment Income (Loss) and Adjusted Other Net Loss

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 11, 2021, include a discussion of adjusted segment income (loss) and adjusted other net loss for the year-to-date period ended December 31, 2020 and a discussion of 2020 and 2021 forecasted adjusted segment income and forecasted adjusted other net loss.

Adjusted segment income (loss) and adjusted other net loss are non-GAAP financial measures, as they represent reported segment income (loss) and other net loss adjusted for special items (as discussed above under Adjusted EPS). Management believes the presentation of adjusted segment income (loss) and adjusted other net expense provides useful information to investors, as it provides an additional relevant comparison of a segment's or Other's performance across periods. When a per share impact is provided for a segment income (loss) driver, the after-tax driver is derived using the pretax amount of the item less income taxes based on the segment statutory tax rate of 24% for Electric Utilities and Infrastructure, 23% for Gas Utilities and Infrastructure and Other, or an effective tax rate for Commercial Renewables. The after-tax earnings drivers are divided by the Duke Energy weighted average shares outstanding for the period. The most directly comparable GAAP measures for adjusted segment income (loss) and adjusted other net loss are reported segment income (loss) and other net loss, which represents segment income (loss) and other net loss from continuing operations, including any special items. Reconciliations of adjusted segment income (loss) and adjusted other net loss for the year-to-date period ended December 31, 2020, to the most directly comparable GAAP measures is included herein. Due to the forward-looking nature of any forecasted adjusted segment income (loss) and forecasted other net loss and any related growth rates for future periods, information to reconcile these non-GAAP financial measures to the most directly comparable GAAP financial measures are not available at this time, as the company is unable to forecast all special items, as discussed above under Adjusted EPS guidance.

Effective Tax Rate Including Impacts of Noncontrolling Interests and Preferred Dividends and Excluding Special Items

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 11, 2021, include a discussion of the effective tax rate including impacts of noncontrolling interests and preferred dividends and excluding special items for the year-to-date period ended December 31, 2020. The materials also include a discussion of the 2020 and 2021 forecasted effective tax rate including impacts of noncontrolling interests and preferred dividends and excluding special items. Effective tax rate including impacts of noncontrolling interests and preferred dividends and excluding special items is a non-GAAP financial measure as the rate is calculated using pretax income and income tax expense, both adjusted for the impact of special items, noncontrolling interests and preferred dividends. The most directly comparable GAAP measure is reported effective tax rate, which includes the impact of special items and excludes the impacts of noncontrolling interests and preferred dividends. A reconciliation of this non-GAAP financial measure for the year-to-date period ended December 31, 2020, to the most directly comparable GAAP measure is included herein. Due to the forward-looking nature of the forecasted effective tax rates including impacts of noncontrolling interests and preferred dividends and excluding special items, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted EPS Guidance.

Adjusted Book Return on Equity (ROE)

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 11, 2021 include a reference to the historical and projected adjusted book return on equity (ROE) ratio. This ratio is a non-GAAP financial measure. The numerator represents Net Income, adjusted for the impact of special items (as discussed above under Adjusted EPS). The denominator is average Total Common Stockholder's Equity, reduced for Goodwill. A reconciliation of the components of adjusted ROE to the most directly comparable GAAP measures is included here-in. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted EPS Guidance.

Available Liquidity

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 11, 2021, include a discussion of Duke Energy's available liquidity balance. The available liquidity balance presented is a non-GAAP financial measure as it represents cash and cash equivalents, excluding certain amounts held in foreign jurisdictions and cash otherwise unavailable for operations, the remaining availability under Duke Energy's available credit facilities, including the master credit facility as of December 31, 2020. The most directly comparable GAAP financial measure for available liquidity is cash and cash equivalents. A reconciliation of available liquidity as of December 31, 2020, to the most directly comparable GAAP measure is included herein.

Holdco Debt Percentage

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 11, 2021 include a reference to a historical and projected Holdco debt percentage. This percentage reflects a non-GAAP financial measure. The numerator of the Holdco debt percentage is the balance of Duke Energy Corporate debt, Progress Energy, Inc. debt, PremierNotes and the Commercial Paper attributed to the Holding Company. The denominator for the percentage is the balance of long-term debt (excluding purchase accounting adjustments and long-term debt associated with the CR3 Securitization), including current maturities, imputed operating lease liabilities, plus notes payable and commercial paper outstanding.

Funds From Operations ("FFO") Ratio

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 11, 2021 include a reference to the historical and expected FFO to Total Debt ratio. This ratio reflects non-GAAP financial measures. The numerator of the FFO to Total Debt ratio is calculated principally by using net cash provided by operating activities on a GAAP basis, adjusted for changes in working capital, ARO spend, depreciation and amortization of operating leases and reduced for capitalized interest (including any AFUDC interest). The denominator for the FFO to Total Debt ratio is calculated principally by using the balance of long-term debt (excluding purchase accounting adjustments and long-term debt associated with the CR3 Securitization), including current maturities, imputed operating lease liabilities, plus notes payable, commercial paper outstanding, underfunded pension liability, guarantees on joint-venture debt, and adjustments to hybrid debt and preferred stock issuances based on how credit rating agencies view the instruments. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted EPS Guidance.

Net Regulated Electric and Gas O&M

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 11, 2021, include a discussion of Duke Energy's net regulated Electric and Gas operating, maintenance and other expenses (O&M) for the year-to-date periods ended December 31, 2020, 2019, 2018, 2017 and 2016, as well as the forecasted year-to-date period ended December 31, 2021.

Net regulated Electric and Gas O&M is a non-GAAP financial measure, as it represents reported O&M expenses adjusted for special items and expenses recovered through riders and excludes O&M expenses for Duke Energy's non-margin based Commercial businesses and non-regulated electric products and services supporting regulated operations.

Management believes the presentation of net regulated Electric and Gas O&M provides useful information to investors, as it provides a meaningful comparison of financial performance across periods. The most directly comparable GAAP financial measure for net regulated Electric and Gas O&M is reported operating, maintenance and other expenses. A reconciliation of net regulated Electric and Gas O&M for the year-to-date periods ended December 31, 2020, 2019, 2018, 2017 and 2016, as well as the forecasted year-to-date period ended December 31, 2021, to the most directly comparable GAAP measure are included here-in.

Business Mix Percentage

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 11, 2021, reference each segment's 2021 projected adjusted segment income as a percentage of the total projected 2021 adjusted net income (i.e. business mix), excluding the impact of Other. Duke Energy's segments are comprised of Electric Utilities and Infrastructure, Gas Utilities and Infrastructure and Commercial Renewables.

Adjusted segment income is a non-GAAP financial measure, as it represents reported segment income adjusted for special items as discussed above. Due to the forward-looking nature of any forecasted adjusted segment income, information to reconcile this non-GAAP financial measure to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items (as discussed above under Adjusted EPS Guidance).

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Year Ended December 31, 2020
(Dollars in millions, except per share amounts)

		Special Items					
	Reported Earnings	Gas Pipeline Investments	Severance	Regulatory Settlements	Discontinued Operations	Total Adjustments	Adjusted Earnings
SEGMENT INCOME (LOSS)							
Electric Utilities and Infrastructure	**$ 2,669**	$ 4 **A**	$ —	$ 872 **D**	$ —	$ 876	$ 3,545
Gas Utilities and Infrastructure	**(1,266)**	1,707 **B**	—	—	—	1,707	441
Commercial Renewables	**286**	—	—	—	—	—	286
Total Reportable Segment Income	**1,689**	**1,711**	**—**	**872**	**—**	**2,583**	**4,272**
Other	**(426)**	—	(75) **C**		—	(75)	(501)
Discontinued Operations	**7**		—	—	(7) **E**	(7)	—
Net Income Available to Duke Energy Corporation Common Stockholders	**$ 1,270**	**$ 1,711**	**$ (75)**	**$ 872**	**$ (7)**	**$ 2,501**	**$ 3,771**
EPS AVAILABLE TO DUKE ENERGY CORPORATION COMMON STOCKHOLDERS	**$ 1.72**	**$ 2.32**	**$ (0.10)**	**$ 1.19**	**$ (0.01)**	**$ 3.40**	**$ 5.12**

A - Net of $1 million tax benefit. $5 million included within Impairment charges related to gas pipeline interconnections on the Duke Energy Progress' Consolidated Statements of Operations.

B - Net of $398 million tax benefit.

- $2,098 million recorded within Equity in (losses) earnings of unconsolidated affiliates related to exit obligations for gas pipeline investments on the Consolidated Statements of Operations.
- $7 million included within Impairment charges related to gas project materials on the Piedmont Consolidated Statements of Operations.

C - Net of $23 million tax expense. $98 million reversal of 2018 severance charges recorded within Operations, maintenance and other on the Consolidated Statements of Operations.

D - Net of $123 million tax benefit at Duke Energy Carolinas and $140 million tax benefit at Duke Energy Progress.

- $454 million included within Impairment charges and reversal of $50 million included in Regulated electric operating revenues related to the coal ash settlement filed with the NCUC on the Duke Energy Carolinas' Consolidated Statements of Operations.
- $19 million included within Impairment charges related to the Clemson University Combined Heat and Power Plant and $8 million of shareholder contributions within Operations, maintenance and other on the Duke Energy Carolinas' Consolidated Statements of Operations.
- $494 million included within Impairment charges and reversal of $102 million included in Regulated electric operating revenues related to the coal ash settlement filed with NCUC on the Duke Energy Progress' Consolidated Statements of Operations.
- $8 million of shareholder contributions included within Operations, maintenance and other on the Duke Energy Progress' Consolidated Statements of Operations.

E - Recorded in Income (Loss) from Discontinued Operations, net of tax on the Consolidated Statements of Operations.

Weighted Average Shares (reported and adjusted) – 737 million

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Year Ended December 31, 2019
(Dollars in millions, except per share amounts)

	Reported Earnings	Special Items: Impairment Charges	Discontinued Operations	Total Adjustments	Adjusted Earnings
SEGMENT INCOME					
Electric Utilities and Infrastructure	**$ 3,536**	$ (27) **A**	$ —	$ (27)	$ 3,509
Gas Utilities and Infrastructure	**432**	19 **B**	—	19	451
Commercial Renewables	**198**	—	—	—	198
Total Reportable Segment Income	**4,166**	**(8)**	**—**	**(8)**	**4,158**
Other	**(452)**	—	—	—	(452)
Discontinued Operations	**(7)**	—	7 **C**	7	—
Net Income Available to Duke Energy Corporation Common Stockholders	**$ 3,707**	**$ (8)**	**$ 7**	**$ (1)**	**$ 3,706**
EPS AVAILABLE TO DUKE ENERGY CORPORATION COMMON STOCKHOLDERS	**$ 5.06**	**$ (0.01)**	**$ 0.01**	**$ —**	**$ 5.06**

Note: Earnings Per Share amounts are adjusted for accumulated but not yet declared dividends for Series B Preferred Stock of $(0.02).

A – Net of $9 million tax expense. $36 million reduction of a prior year impairment at Citrus County CC recorded within Impairment charges on Duke Energy Florida's Consolidated Statements of Operations.

B – Net of $6 million tax benefit. $25 million included within Other Income and Expenses on the Consolidated Statements of Operations, related to the other-than-temporary-impairment of the remaining investment in Constitution Pipeline Company, LLC.

C – Recorded in Income (Loss) from Discontinued Operations, net of tax, on the Consolidated Statements of Operations.

Weighted Average Shares (reported and adjusted) – 729 million

DUKE ENERGY CORPORATION
EFFECTIVE TAX RECONCILIATION
December 2020
(Dollars in millions)

	Three Months Ended December 31, 2020		Year Ended December 31, 2020	
	Balance	Effective Tax Rate	Balance	Effective Tax Rate
Reported (Loss) Income Before Income Taxes From Continuing Operations Before Income Taxes	$ (319)		$ 839	
Regulatory Settlements	1,100		1,135	
Gas Pipeline Investments	20		2,110	
Severance	—		(98)	
Noncontrolling Interests	87		295	
Preferred Dividends	(14)		(107)	
Pretax Income Including Noncontrolling Interests and Preferred Dividends and Excluding Special Items	$ 874		$ 4,174	
Reported Income Tax Benefit From Continuing Operations	$ (162)	50.8 %	$ (236)	(28.1)%
Regulatory Settlements	255		263	
Gas Pipeline Investments	4		399	
Severance	—		(23)	
Tax Expense Including Noncontrolling Interests and Preferred Dividends and Excluding Special Items	$ 97	11.1%	$ 403	9.7 %

	Three Months Ended December 31, 2019		Year Ended December 31, 2019	
	Balance	Effective Tax Rate	Balance	Effective Tax Rate
Reported Income From Continuing Operations Before Income Taxes	$ 709		$ 4,097	
Impairment Charges	14		(11)	
Noncontrolling Interests	67		177	
Preferred Dividends	(14)		(41)	
Pretax Income Including Noncontrolling Interests and Preferred Dividends and Excluding Special Items	$ 776		$ 4,222	
Reported Income Tax Expense From Continuing Operations	$ 95	13.4 %	$ 519	12.7 %
Impairment Charges	3		(3)	
Tax Expense Including Noncontrolling Interests and Preferred Dividends and Excluding Special Items	$ 98	12.6%	$ 516	12.2 %

Duke Energy Corporation
Available Liquidity Reconciliation
As of December 31, 2020
(In millions)

Cash and Cash Equivalents	$ 259	
Less: Certain Amounts Held in Foreign Jurisdictions	(3)	
Less: Unavailable Domestic Cash	(48)	
	208	
Plus: Remaining Availability under Master Credit Facilities and other facilities	6,140	
Total Available Liquidity (a), December 31, 2020	$ 6,348	approximately 6.3 billion

(a) The available liquidity balance presented is a non-GAAP financial measure as it represents Cash and cash equivalents, excluding certain amounts held in foreign jurisdictions and cash otherwise unavailable for operations, and remaining availability under Duke Energy's available credit facilities, including the master credit facility, as of December 31, 2020. The most directly comparable GAAP financial measure for available liquidity is Cash and cash equivalents.

Duke Energy Corporation
Operations, Maintenance and Other Expense
(In millions)

	Actual December 31, 2016	Actual December 31, 2017	Actual December 31, 2018	Actual December 31, 2019	Actual December 31, 2020	Forecast December 31, 2021
Operation, maintenance and other[(a)]	**$6,223**	**$5,944**	**$6,463**	**$6,066**	**$5,788**	**$6,072**
Adjustments:						
Costs to Achieve, Mergers[(b)]	(238)	(94)	(83)	–	–	–
Severance[(b)]	(92)	–	(187)	–	98	–
Regulatory settlement[(b)]	–	(5)	(40)	–	(16)	–
Reagents Recoverable[(d)]	(63)	(60)	(78)	(71)	(53)	(58)
Energy Efficiency Recoverable[(c)]	(417)	(485)	(446)	(415)	(350)	(403)
Other Deferrals[(e)] and Recoverable[(d)]	(78)	(92)	(323)	(282)	(457)	(282)
Margin based O&M for Commercial Businesses	(185)	(94)	(113)	(95)	(67)	(208)
Short-term incentive payments (over)/under budget	(90)	(22)	(30)	(112)	33	–
Non-Margin based O&M for Commercial Businesses [(f)]	(166)	(173)	(191)	(203)	(218)	(269)
Non-regulated Electric Products and Services[(g)]	(83)	(140)	(138)	(175)	(210)	(223)
Net Regulated Electric and Gas, operation, maintenance and other	**$ 4,811**	**$ 4,779**	**$ 4,835**	**$ 4,714**	**$ 4,548**	**$ 4,630**

(a) As reported in the Consolidated Statements of Operations.
(b) Presented as a special item for the purpose of calculating adjusted earnings and adjusted diluted earnings per share.
(c) Primarily represents expenses to be deferred or recovered through rate riders.
(d) The Duke Energy Indiana Rate Case was effective in mid-year 2020. This Rate Case permitted recovery within base rates of certain costs tha had previously been recovered through riders. Accordingly, all prior periods have been recast as if these costs were always included within base rates.
(e) Prior periods have been recast to reflect a change in methodology to present certain deferrals which will be recovered through future rate cases as if they were included in base rates.
(f) Primarily represents the operations, maintenance and other expense of the Commercial Renewables segment excluding REC Solar.
(g) Primarily represents non-regulated electric products and services expense in support of regulated operations.

DUKE ENERGY CORPORATION
ADJUSTED BOOK RETURN ON EQUITY (ROEs)
For the period ended December 31, 2020
dollars in millions

	Duke Energy Carolinas	Duke Energy Progress	Total Carolinas	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio Reportable Segments	Piedmont
Reported Net Income 2020	$ 956	$ 415	$ 1,371	$ 771	$ 408	$ 258 (2)	$ 264 (3)
Special Items (1)	358	443	801	-	-	-	7
Adjusted Net Income 2020	1,314	858	2,172	771	408	258	271
2020							
Equity	13,154	9,260	22,414	7,558	4,783	3,935	2,647 (4)
Goodwill	-	-	-	-	-	920	49
Equity less Goodwill	13,154	9,260	22,414	7,558	4,783	3,015	2,598
2019							
Equity	12,811	9,246	22,057	6,788	4,575	3,687	2,381 (4)
Goodwill	-	-	-	-	-	920	49
Equity less Goodwill	12,811	9,246	22,057	6,788	4,575	2,767	2,332
Average Equity less Goodwill			22,236	7,173	4,679	2,891	2,465
Adjusted Book ROEs			9.8%	10.7%	8.7%	8.9%	11.0%

(1) Impacts of Regulatory settlement for coal ash, net of tax; Impairment charges for interconnection with ACP, net of tax; Impairment charges and shareholder contributions related to Clemson CHP, net of tax; Severance, net of tax

(2) Net Income for 2020 equals Duke Energy Ohio reportable segments segment income

(3) Piedmont Natural Gas Net Income excludes $9 million of income related to Investments in Gas Transmission Infrastructure.

2020
273
(9)
264

(4) Reconciliation of Piedmont Natural Gas Equity to reported equity:

	2020	2019
Reported Equity for Piedmont Natural Gas	2,715	2,443
Less: Investments in Gas Transmission Infrastructure	68	62
Piedmont Natural Gas Adjusted Equity	2,647	2,381

DUKE ENERGY CORPORATION
ADJUSTED BOOK RETURN ON EQUITY (ROEs)
For the period ended December 31, 2019
dollars in millions

	Duke Energy Carolinas	Duke Energy Progress	Total Carolinas	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio Reportable Segments		Piedmont	
Reported Net Income 2019	$ 1,403	$ 805	$ 2,208	$ 693	$ 436	$ 244	(2)	$ 196	(4)
Special Items (1)	-	-	-	(27)	-	-		-	
Adjusted Net Income 2019	1,403	805	2,208	666	436	244		196	
2019									
Equity	12,811	9,246	22,057	6,788	4,575	3,687	(3)	2,381	(5)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	12,811	9,246	22,057	6,788	4,575	2,767		2,332	
2018									
Equity	11,683	8,441	20,124	6,095	4,339	3,449	(3)	2,047	(5)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	11,683	8,441	20,124	6,095	4,339	2,529		1,998	
Average Equity less Goodwill			21,091	6,442	4,457	2,648		2,165	
Adjusted Book ROEs			10.5%	10.3%	9.8%	9.2%		9.1%	

(1) Impacts of Citrus County CC, Net of Tax

(2) Net Income for 2019 equals Duke Energy Ohio reportable segments segment income

(3) Reconciliation of Duke Energy Ohio Equity to Equity of the reportable segments:

	2019	2018
Reported Equity for Duke Energy Ohio	3,683	3,445
Less: Non-Reg & Other	(4)	(4)
Duke Energy Ohio Reportable Segments Equity	3,687	3,449

(4) Piedmont Natural Gas Net Income excludes $6 million of income related to Investments in Gas Transmission Infrastructure.

2019
202
(6)
196

(5) Reconciliation of Piedmont Natural Gas Equity to reported equity:

	2019	2018
Reported Equity for Piedmont Natural Gas	2,443	2,091
Less: Investments in Gas Transmission Infrastructure	62	44
Piedmont Natural Gas Adjusted Equity	2,381	2,047

DUKE ENERGY CORPORATION
ADJUSTED BOOK RETURN ON EQUITY (ROEs)
For the period ended December 31, 2018
dollars in millions

	Duke Energy Carolinas	Duke Energy Progress	Total Carolinas	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio Reportable Segments		Piedmont	
Reported Net Income 2018	$ 1,071	$ 667	$ 1,738	$ 553	$ 393	$ 279	(2)	$ 124	(4)
Special Items (1)	234	118	352	63	8	-		40	
Adjusted Net Income 2018	1,305	785	2,090	616	401	279		164	
2018									
Equity	11,683	8,441	20,124	6,095	4,339	3,449	(3)	2,047	(5)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	11,683	8,441	20,124	6,095	4,339	2,529		1,998	
2017									
Equity	11,361	7,949	19,310	5,618	4,121	3,166	(3)	1,616	(5)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	11,361	7,949	19,310	5,618	4,121	2,246		1,567	
Average Equity less Goodwill			19,717	5,857	4,230	2,388		1,783	
Adjusted Book ROEs			10.6%	10.5%	9.5%	11.7%		9.2%	

(1) Costs to Achieve (CTA) Mergers net of tax, Severance, Regulatory and Legislative Impacts and Tax Reform.

(2) Net Income for 2018 equals Duke Energy Ohio reportable segments segment income, which already excludes CTA and cost savings initiatives, Severance and Sale of Retired Plant.

(3) Reconciliation of Duke Energy Ohio Equity to Equity of the reportable segments:

	2018	2017
Reported Equity for Duke Energy Ohio	3,445	3,163
Less: Non-Reg & Other	(4)	(3)
Duke Energy Ohio Reportable Segments Equity	3,449	3,166

(4) Piedmont Natural Gas Net Income excludes $5 million of income related to Investments in Gas Transmission Infrastructure.

(5) Reconciliation of Piedmont Natural Gas Equity to reported equity:

	2018	2017
Reported Equity for Piedmont Natural Gas	2,091	1,662
Less: Investments in Gas Transmission Infrastructure	44	46
Piedmont Natural Gas Adjusted Equity	2,047	1,616

Duke Energy Corporation
2021 Forecasted Cash Flow Reconciliation, Required by SEC Regulation G
February 11, 2021
($ in millions)

		Forecast 2021
Primary Sources:		
Adjusted net income (1)	(a)	$3,960
Depreciation & amortization	(a)	5,655
Deferred and accrued taxes	(a)	325
Other sources / (uses), net	(a)	600
Total Sources		10,540
Primary Uses:		
Capital expenditures (including discretionary)	(b)	(10,475)
Dividends	(c)	(3,000)
Total Uses		(13,475)
Uses in Excess of Sources		(2,935)
Net Change in Financing		
Debt issuances	(c, d)	8,275
Debt maturities	(c)	(5,335)
Net Change in Debt		2,940
Preferred stock issuances		
Common stock issuances	(c)	
Net Change in Cash		$5
Reconciliations to forecasted U.S. GAAP reporting amounts:		
Operating cash flow components, sum of (a) from above		$10,540
Reconciling items to GAAP cash flows from operating activities	(2)	(2,135)
Net cash provided by operating activities per GAAP Consolidated Statement of Cash Flows		$8,405
Investing cash flow components, (b) from above		($10,475)
Reconciling items to GAAP cash flows from investing activities	(2)	(595)
Net cash used in investing activities per GAAP Consolidated Statement of Cash Flows		($11,070)
Financing cash flow components, sum of (c) from above		($60)
Reconciling items to GAAP cash flows from financing activities	(2)	2,730
Net cash provided by financing activities per GAAP Consolidated Statement of Cash Flows		$2,670
Debt issuances [(d) from above] includes "Notes payable and commercial paper" which is separately presented per GAAP Consolidated Statements of Cash Flows		
Net increase in cash and cash equivalents per forecasted GAAP Consolidated Statements of Cash Flows		$5

Notes:

(1) The forecasted adjusted net income of $3,960 million for 2021 is an illustrative amount based on the midpoint of Duke Energy's adjusted basic EPS outlook range of $5.00-$5.30 per share. Adjusted basic EPS is a non-GAAP financial measure as it represents basic EPS from continuing operations attributable to Duke Energy Corporation shareholders and adjusted for the per-share impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis, although it is reasonably possible such charges and credits could recur. The most directly comparable GAAP measure for adjusted basic EPS is reported basic EPS from continuing operations attributable to Duke Energy Corporation common shareholders, which includes the impact of special items. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items.

(2) Amount consists primarily of an adjustment for operating cashflow items (principally payments for asset retirement obligations and payment for an accrued liability) included in the "Capital expenditures (including discretionary)" and "Debt maturities", which are combined for the GAAP reconciliation in Investing activities and Financing activities, and; an adjustment for investing cash flow items (principally cost of removal expenditures, proceeds from sales and maturities of available-for-sale securities and Other) included in the "Other sources/(uses), net", which are combined for the GAAP reconciliation in Operating activities, and; an adjustment for financing cash flow items (principally proceeds from Noncontrolling Interests initial investments, payments for interest on preferred debt/equity content securities, and Other) included in the "Other sources/(uses), net" and "Capital expenditures (including discretionary)', which are combined for the GAAP reconciliation in Operating activities and Investing activities.

FFO to Debt Calculation
Duke Energy Corporation
(in millions)

	Year Ended December 31, 2020 Actual
Cash From Operations	8,856
Adjust for Working Capital (1)	(246)
Coal ash ARO spend	610
Include Capitalized Interest as cost	(112)
Hybrid interest adjustment	10
Preferred stock adjustment	(54)
CR3 securitization adjustment	(55)
ACP construction loan interest adjustment	(22)
Lease-imputed FFO adjustment (D&A)	260
Funds From Operations	**9,247**
Notes payable and commercial paper	2,873
Current maturities of LT debt	4,238
LT debt	55,625
Less: Purchase Accounting adjustments	(1,711)
CR3 securitization	(1,057)
Underfunded Pension	397
ACP construction loan	860
Hybrid debt adjustment	(250)
Preferred stock adjustment	1,000
Lease-imputed debt	1,517
Total Balance Sheet Debt (Including ST)	**63,492**
(1) Working capital detail, excluding MTM	
Receivables	(56)
Inventory	66
Other current assets	205
Accounts payable	(21)
Taxes accrued	117
Other current liabilities	(65)
	246
FFO / Debt	**15%**

FFO to Debt Calculation
Duke Energy Carolinas
(in millions)

	Year Ended December 31, 2020 Actual
Cash From Operations	2,776
Adjust for Working Capital (1)	(255)
ARO spend	162
Include Capitalized Interest as cost	(28)
Lease-imputed FFO adjustment (D&A)	43
Funds From Operations	**2,698**
Current maturities of LT debt	506
LT debt	11,412
LT debt payable to affiliates	300
Notes payable to affiliated companies	506
Underfunded Pension	13
Lease imputed debt	117
Total Balance Sheet Debt (Including ST)	**12,854**
(1) Working capital detail, excluding MTM	
Receivables	52
Receivables from affiliates	(10)
Inventory	(14)
Other current assets	209
Accounts payable	55
Accounts payable to affiliates	(11)
Taxes accrued	30
Other current liabilities	(56)
	255
FFO / Debt	**21%**

FFO to Debt Calculation
Duke Energy Progress
(in millions)

	Year Ended December 31, 2020 Actual
Cash From Operations	1,666
Adjust for Working Capital (1)	(229)
Coal ash ARO spend	304
Include Capitalized Interest as cost	(12)
Lease-imputed FFO adjustment (D&A)	60
Funds From Operations	**1,789**
Notes payable to affiliated companies	295
Current maturities of LT debt	603
LT debt	8,505
LT debt payable to affiliates	150
Underfunded Pension	33
Lease imputed debt	354
Total Balance Sheet Debt (Including ST)	**9,940**
(1) Working capital detail, excluding MTM	
Receivables	(4)
Receivables from affiliates	2
Inventory	23
Other current assets	98
Accounts payable	(127)
Accounts payable to affiliates	12
Taxes accrued	68
Other current liabilities	157
	229
FFO / Debt	**18%**

FFO to Debt Calculation
Duke Energy Florida
(in millions)

	Year Ended December 31, 2020 Actual
Cash From Operations	1,661
Adjust for Working Capital (1)	(51)
Coal ash ARO spend	80
Include Capitalized Interest as cost	(5)
Adjust for CR3	(55)
Lease-imputed FFO adjustment (D&A)	99
Funds From Operations	**1,729**
Notes payable to affiliated companies	196
Current maturities of LT debt	823
LT debt	7,092
Adjust for CR3	(1,057)
Lease imputed debt	342
Underfunded Pension	123
Total Balance Sheet Debt (Including ST)	**7,519**
(1) Working capital detail, excluding MTM	
Receivables	(64)
Receivables from affiliates	(3)
Inventory	26
Other current assets	40
Accounts payable	66
Accounts payable to affiliates	(46)
Taxes accrued	39
Other current liabilities	(7)
	51
FFO / Debt	**23%**

FFO to Debt Calculation
Duke Energy Indiana
(in millions)

	Year Ended December 31, 2020 Actual
Cash From Operations	938
Adjust for Working Capital (1)	(57)
Coal ash ARO spend	63
Include Capitalized Interest as cost	(10)
Lease-imputed FFO adjustment (D&A)	16
Funds From Operations	**950**
Notes payable to affiliated companies	131
Current maturities of LT debt	70
LT debt	3,871
LT debt payable to affiliates	150
CRC	186
Underfunded pension	112
Lease imputed debt	56
Total Balance Sheet Debt (Including ST)	**4,576**
(1) Working capital detail, excluding MTM	
Receivables	8
Inventory	44
Other current assets	(3)
Accounts payable	(12)
Accounts payable to affiliates	1
Taxes accrued	13
Other current liabilities	6
	57
FFO / Debt	**21%**

FFO to Debt Calculation
Duke Energy Ohio
(in millions)

	Year Ended December 31, 2020 Actual
Cash From Operations	575
Adjust for Working Capital (1)	(38)
Coal Ash ARO spend	2
Include capitalized Interest as cost	(26)
Lease-imputed FFO adjustment (D&A)	10
Funds From Operations	**523**
Notes payable to affiliated companies	169
Current maturities of LT debt	50
LT debt	3,014
LT debt payable to affiliates	25
CRC	138
Underfunded pension	92
Lease imputed debt	21
Total Balance Sheet Debt (Including ST)	**3,509**
(1) Working capital detail, excluding MTM	
Receivables	(13)
Receivables from affiliates	9
Inventory	25
Other current assets	(18)
Accounts payable	2
Taxes accrued	30
Other current liabilities	3
	38
FFO / Debt	**15%**

FFO to Debt Calculation
Piedmont Natural Gas
(in millions)

	Year Ended December 31, 2020 Actual
Cash From Operations	481
Adjust for Working Capital (1)	(31)
Include Capitalized Interest as cost	(8)
Lease-imputed FFO adjustment (D&A)	4
Funds From Operations	**446**
Notes payable to affiliated companies	530
Current maturities of LT debt	160
LT debt	2,620
Underfunded pension	4
Lease imputed debt	23
Total Balance Sheet Debt (Including ST)	**3,337**
(1) Working capital detail, excluding MTM	
Receivables	10
Inventory	3
Other current assets	(66)
Accounts payable	16
Accounts payable to affiliates	76
Taxes accrued	3
Other current liabilities	(11)
	31
FFO / Debt	**13%**

DUKE ENERGY®

Q4 / 2021

Earnings Review and Business Update

Lynn Good / *Chair, President and CEO*
Steve Young / *Executive Vice President and CFO*

February 10, 2022

Safe Harbor statement

This presentation includes forward-looking statements within the meaning of the federal securities laws. Actual results could differ materially from such forward-looking statements. The factors that could cause actual results to differ are discussed herein and in Duke Energy's SEC filings, available at www.sec.gov.

Regulation G disclosure

In addition, today's discussion includes certain non-GAAP financial measures as defined under SEC Regulation G. A reconciliation of those measures to the most directly comparable GAAP measures is available in the Appendix herein and on our Investor Relations website at www.duke-energy.com/investors/.

Safe harbor statement

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions and can often be identified by terms and phrases that include "anticipate," "believe," "intend," "estimate," "expect," "continue," "should," "could," "may," "plan," "project," "predict," "will," "potential," "forecast," "target," "guidance," "outlook" or other similar terminology. Various factors may cause actual results to be materially different than the suggested outcomes within forward-looking statements; accordingly, there is no assurance that such results will be realized. These factors include, but are not limited to: The impact of the COVID-19 pandemic; State, federal and foreign legislative and regulatory initiatives, including costs of compliance with existing and future environmental requirements, including those related to climate change, as well as rulings that affect cost and investment recovery or have an impact on rate structures or market prices; The extent and timing of costs and liabilities to comply with federal and state laws, regulations and legal requirements related to coal ash remediation, including amounts for required closure of certain ash impoundments, are uncertain and difficult to estimate; The ability to recover eligible costs, including amounts associated with coal ash impoundment retirement obligations, asset retirement and construction costs related to carbon emissions reductions, and costs related to significant weather events, and to earn an adequate return on investment through rate case proceedings and the regulatory process; The costs of decommissioning nuclear facilities could prove to be more extensive than amounts estimated and all costs may not be fully recoverable through the regulatory process; Costs and effects of legal and administrative proceedings, settlements, investigations and claims; Industrial, commercial and residential growth or decline in service territories or customer bases resulting from sustained downturns of the economy and the economic health of our service territories or variations in customer usage patterns, including energy efficiency efforts, natural gas building and appliance electrification, and use of alternative energy sources, such as self-generation and distributed generation technologies; Federal and state regulations, laws and other efforts designed to promote and expand the use of energy efficiency measures, natural gas electrification, and distributed generation technologies, such as private solar and battery storage, in Duke Energy service territories could result in a reduced number of customers, excess generation resources as well as stranded costs; Advancements in technology; Additional competition in electric and natural gas markets and continued industry consolidation; The influence of weather and other natural phenomena on operations, including the economic, operational and other effects of severe storms, hurricanes, droughts, earthquakes and tornadoes, including extreme weather associated with climate change; Changing customer expectations and demands including heightened emphasis on environmental, social and governance concerns; The ability to successfully operate electric generating facilities and deliver electricity to customers including direct or indirect effects to the company resulting from an incident that affects the U.S. electric grid or generating resources; Operational interruptions to our natural gas distribution and transmission activities; The availability of adequate interstate pipeline transportation capacity and natural gas supply; The impact on facilities and business from a terrorist attack, cybersecurity threats, data security breaches, operational accidents, information technology failures or other catastrophic events, such as fires, explosions, pandemic health events or other similar occurrences; The inherent risks associated with the operation of nuclear facilities, including environmental, health, safety, regulatory and financial risks, including the financial stability of third-party service providers; The timing and extent of changes in commodity prices and interest rates and the ability to recover such costs through the regulatory process, where appropriate, and their impact on liquidity positions and the value of underlying assets; The results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings, interest rate fluctuations, compliance with debt covenants and conditions, an individual utility's generation mix, and general market and economic conditions; Credit ratings of the Duke Energy Registrants may be different from what is expected; Declines in the market prices of equity and fixed-income securities and resultant cash funding requirements for defined benefit pension plans, other post-retirement benefit plans and nuclear decommissioning trust funds; Construction and development risks associated with the completion of the Duke Energy Registrants' capital investment projects, including risks related to financing, obtaining and complying with terms of permits, meeting construction budgets and schedules and satisfying operating and environmental performance standards, as well as the ability to recover costs from customers in a timely manner, or at all; Changes in rules for regional transmission organizations, including changes in rate designs and new and evolving capacity markets, and risks related to obligations created by the default of other participants; The ability to control operation and maintenance costs; The level of creditworthiness of counterparties to transactions; The ability to obtain adequate insurance at acceptable costs; Employee workforce factors, including the potential inability to attract and retain key personnel; The ability of subsidiaries to pay dividends or distributions to Duke Energy Corporation holding company (the Parent);The performance of projects undertaken by our nonregulated businesses and the success of efforts to invest in and develop new opportunities; The effect of accounting pronouncements issued periodically by accounting standard-setting bodies; Asset or business acquisitions and dispositions, including our ability to successfully consummate the second closing of the minority investment in Duke Energy Indiana or that the sale may not yield the anticipated benefits; The impact of U.S. tax legislation to our financial condition, results of operations or cash flows and our credit ratings; The impacts from potential impairments of goodwill or equity method investment carrying values; The actions of activist shareholders could disrupt our operations, impact our ability to execute on our business strategy, or cause fluctuations in the trading price of our common stock; and the ability to implement our business strategy, including its carbon emission reduction goals..

Additional risks and uncertainties are identified and discussed in the Duke Energy Registrants' reports filed with the SEC and available at the SEC's website at sec.gov. In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than described. Forward-looking statements speak only as of the date they are made and the Duke Energy Registrants expressly disclaim an obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

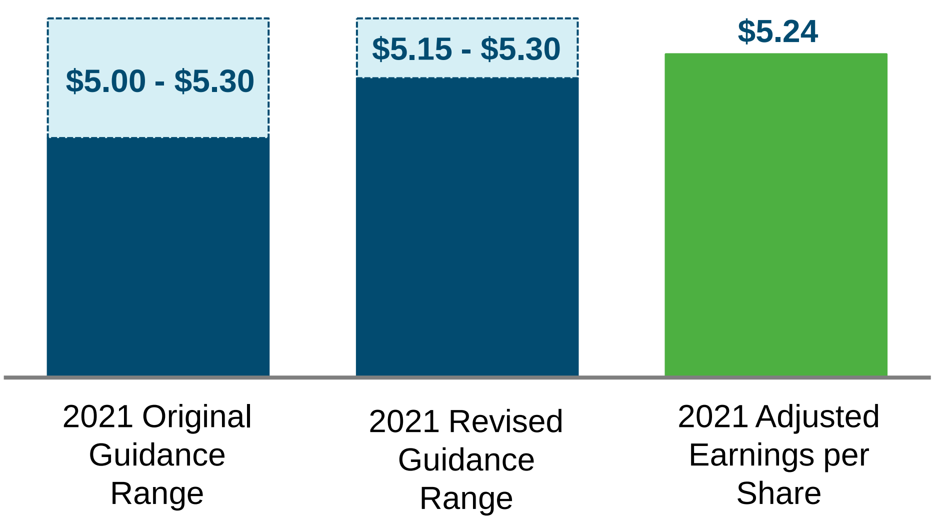
Financial highlights

$4.94 / $5.24

2021 REPORTED / ADJUSTED EPS

ADJUSTED EPS ABOVE MIDPOINT OF REVISED GUIDANCE RANGE

ADJUSTED EARNINGS PER SHARE



$5.30 - $5.60

2022 ADJUSTED EPS GUIDANCE RANGE

5% – 7%

EARNINGS GROWTH THROUGH 2026

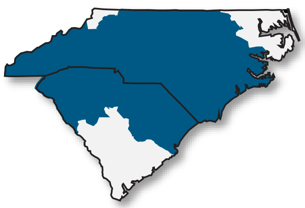
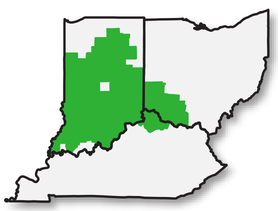
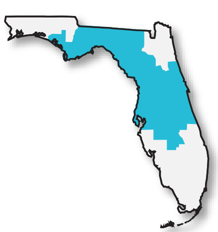
REAFFIRMING AND EXTENDING GROWTH RATE OFF MIDPOINT OF ORIGINAL 2021 GUIDANCE RANGE ($5.15)(1)

$63 BILLION 5-YR CAPEX PLAN

$4 BILLION INCREASE TO 2021-2025 CAPEX PLAN

(1) Based on adjusted EPS

Progress on energy transition across our regions

REGION	2021 ACCOMPLISHMENTS	2022 INITIATIVES
	✓ Collaborated with NC policymakers and stakeholders on bipartisan clean energy legislation ✓ Issued $900 million storm securitization bonds, saving customers roughly 35%, or ~$300 million, over term of the bonds ✓ Filed SLR to extend life of Oconee nuclear	▪ Rulemaking process for HB 951 is underway, with open dockets on performance-based rates (PBR) and coal plant securitization ▪ Ongoing stakeholder engagement on the Carbon Plan to achieve 70% carbon reduction by 2030 vs. 2005 levels
	✓ Submitted Indiana IRP in December, outlining a path to reduce carbon emissions up to 63% by 2030 and exit coal by 2035(1) ✓ Filed Kentucky IRP, accelerating retirement of coal to 2035	▪ Following the Indiana IRP, will issue a request for proposal for generation resources in the coming weeks ▪ Expect to file CPCNs in Indiana by year-end
	✓ Constructive settlement included approval of $1 billion Clean Energy Connection solar program ✓ Installed ~600 MW of solar under existing SOBRA program through 2021	▪ Completing remaining 150 MW through SOBRA ▪ Beginning solar installations under Clean Energy Connection

(1) Based on the preferred portfolio, carbon emission reduction vs. 2005 baseline. Contemplates retiring Edwardsport coal gasifiers by 2035 or adding carbon capture utilization and storage to reduce carbon emissions

Duke Energy is leading the industry's largest clean energy transition

What we're doing

Completing the largest planned coal retirement in the industry

- Retired 56 units (7.5 GW) since 2010
- Coal generation projected to be <5% fuel mix by 2030
- Goal to exit coal generation by 2035[(1)]

Expanding our renewable resources

- Top 10 US renewable company by capacity, with operations in 25 states
- Passed 10 GW owned, operated or purchased in 2021, targeting 24 GW by 2030

Targeting net-zero emissions by 2050

- Reduced carbon emissions 44% since 2005, on pace to exceed 50% reduction by 2030 and net zero by 2050 (Scope 1)
- Net zero methane emissions by 2030 (Scope 1)
- Updating net-zero goal to include Scope 2 and certain Scope 3[(2)] emissions for electric and gas utilities

How we're doing it

Collaborating with state and federal policymakers

- Landmark bipartisan legislation in NC that accelerates our clean energy transition
- Engaging policymakers and regulators to advance shared objectives for clean energy

Integrated resource plans that match our climate goals

- Significant stakeholder engagement on jurisdictional IRPs & NC Carbon Plan
- Balancing affordability and reliability priorities on behalf of our customers

Executing our plan

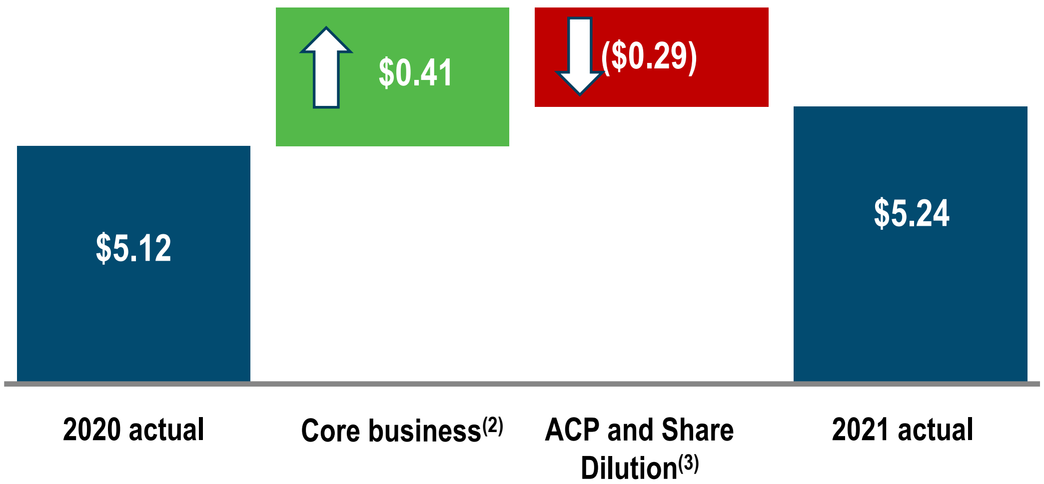
- Constructive rate cases that accelerate coal retirements and call for more renewables
- Extending the life of the largest regulated nuclear fleet in the country
- Managing through supply chain issues
- Leveraging our size and scale to efficiently finance our robust capital plan

(1) Subject to regulatory approvals. Contemplates retiring Edwardsport coal gasifiers by 2035 or adding carbon capture utilization and storage to reduce carbon emissions

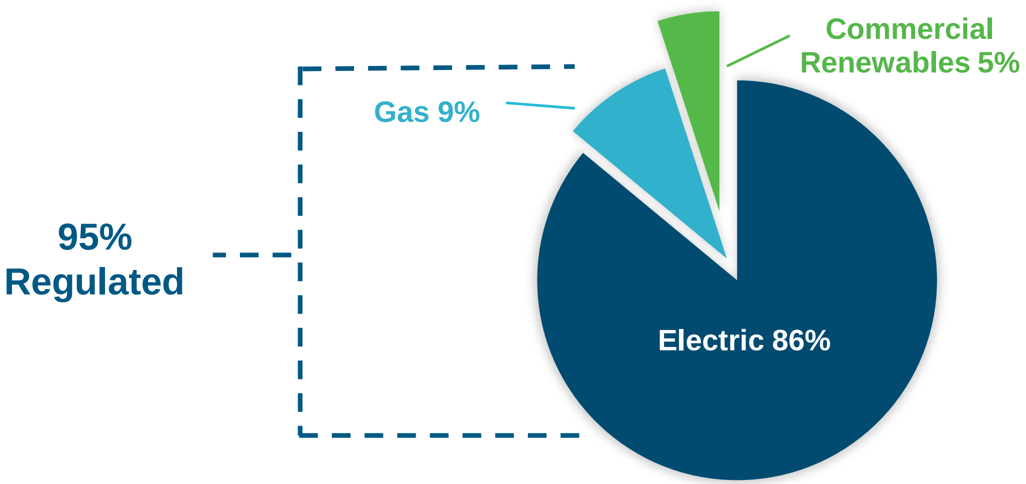
(2) Certain scope 3 emissions include: emissions from upstream fossil fuel procurement, production of power purchased for resale, and from downstream use of sold products in our natural gas distribution business

Financial highlights

2021 ADJUSTED EPS HIGHLIGHTS(1)



EARNINGS CONTRIBUTION(4)

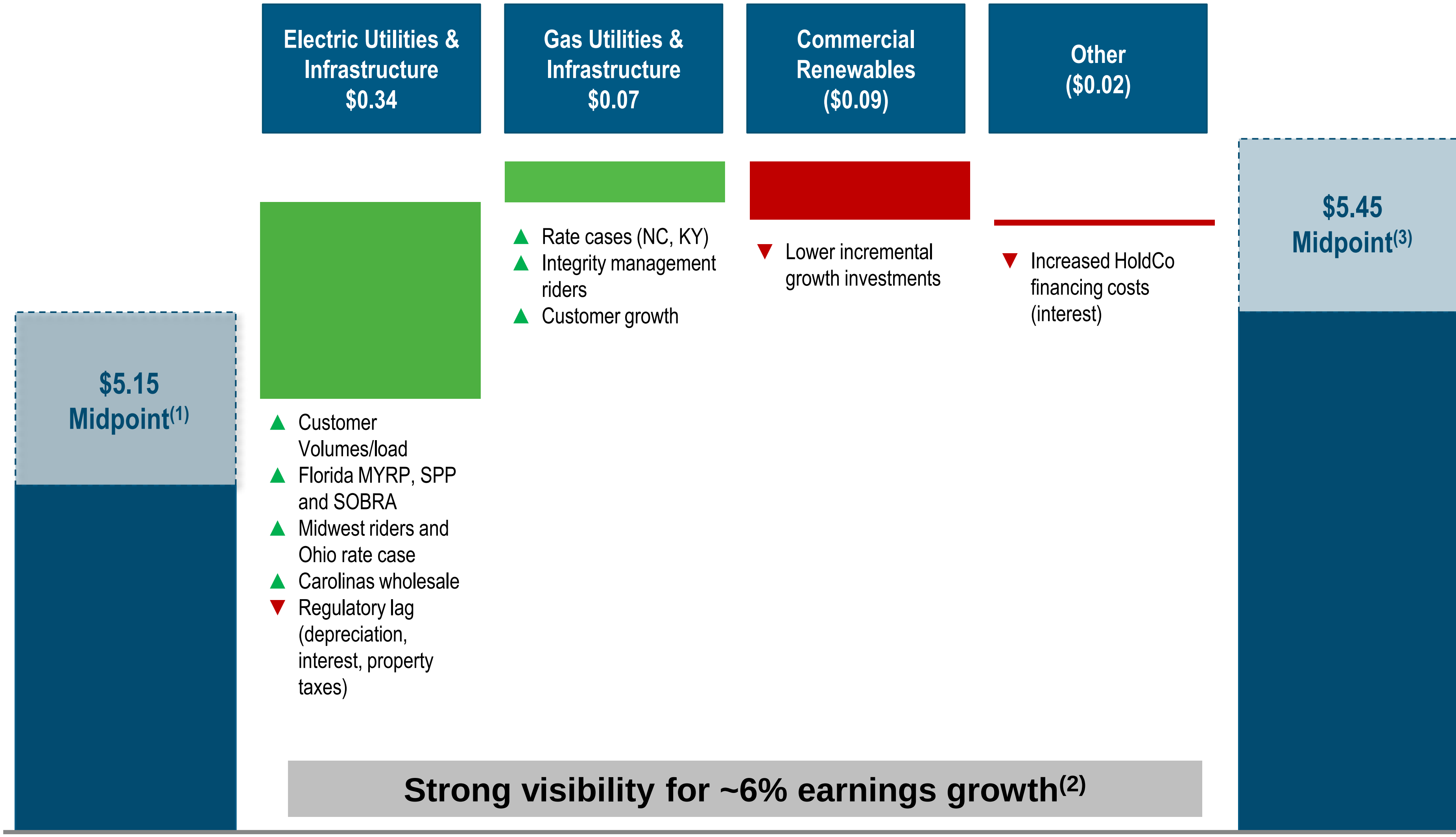


KEY MESSAGES

- Delivered 2021 reported EPS of $4.94 and adjusted EPS of $5.24; above the midpoint of the revised guidance range
- Achieved solid year-over-year core business growth, partially offset by ACP and share dilution
  - Electric Utilities and Infrastructure rate cases (NC, IN, FL), riders, and customer growth - $0.49
  - Gas Utilities and Infrastructure rate cases (NC, TN), riders, and customer growth - $0.03
  - Commercial, including the impact of Winter Storm Uri ($0.11)
  - ACP ($0.07) and share dilution ($0.22)
- Higher year-over-year load of 2%, driven by 1.6% residential customer growth
- Delivered on goal to sustain $200M O&M cost savings identified in 2020

(1) Detailed drivers of adjusted segment income (expense) are available in the Q4 2021 earnings release located on our Investor Relations website at www.duke-energy.com/investors.
(2) Core business growth represents impacts to adjusted EPS excluding the effects of ACP and share dilution.
(3) Based on weighted average basic shares outstanding, including the Dec. 2020 settlement of the $2.47 billion equity forward transaction.
(4) Based on adjusted segment income for the year ended December 31, 2021. Excludes the impact of Other.

2022 Financial outlook – adjusted EPS waterfall



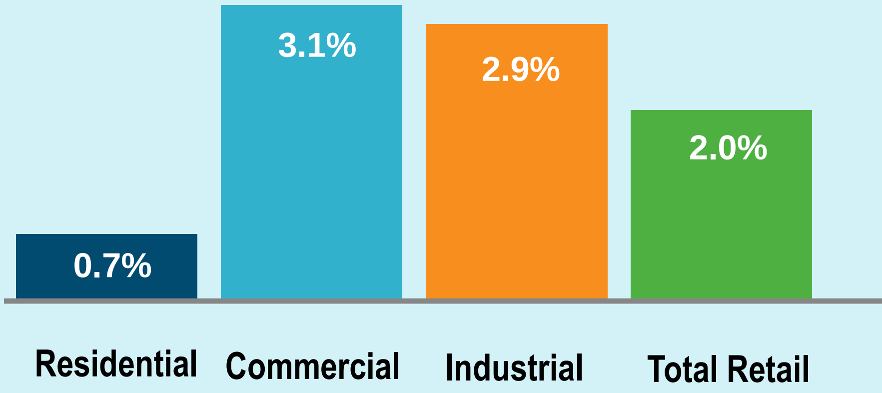
2021 Adjusted EPS Guidance Range of $5.00 - $5.30

2022 Adjusted EPS Guidance Range of $5.30 - $5.60

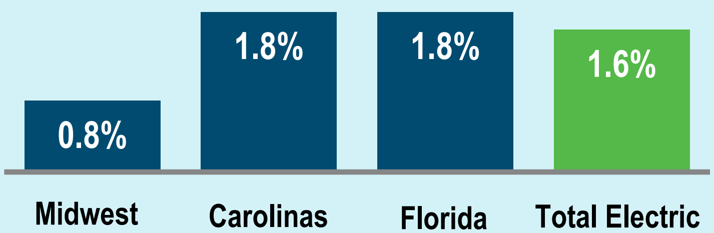
(1) Midpoint of 2021 adjusted EPS original guidance range of $5.00 - $5.30
(2) Based off midpoint of 2021 adjusted EPS original guidance range of $5.00 - $5.30
(3) Midpoint of 2022 adjusted EPS guidance range of $5.30 - $5.60

Retail electric volumes

2021 RETAIL ELECTRIC VOLUMES(1)

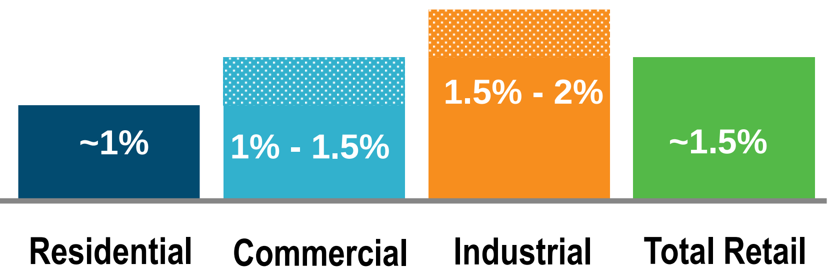


2021 GROWTH IN RESIDENTIAL CUSTOMERS



(1) Compared to 2020 actuals
(2) Compared to 2021 actuals
(3) Source: US Census Bureau and Wells Fargo Economics

FORECASTED 2022 RETAIL ELECTRIC VOLUMES(2)



KEY MESSAGES

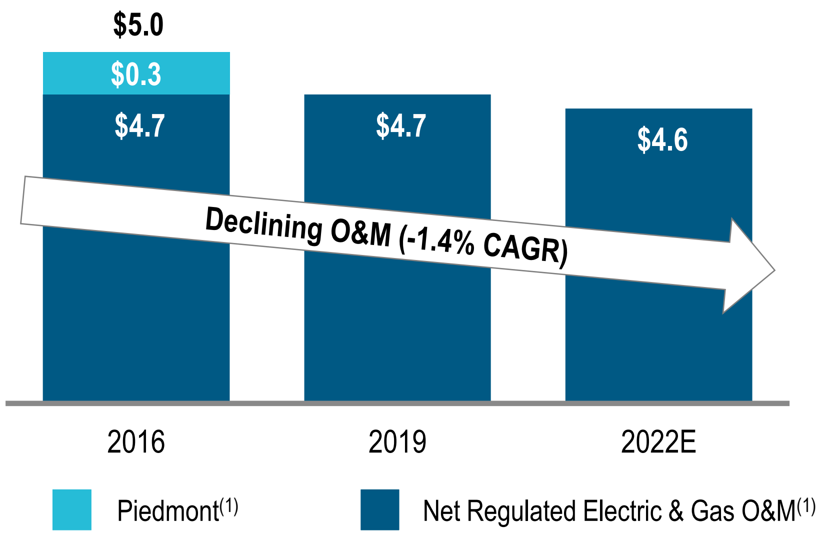
- Expect favorable volume relative to 2021 as economic recovery continues
  - Commercial and Industrial classes not yet back to pre-COVID levels due to labor constraints and Omicron surge
- Outlook for the remainder of the plan is flat to 0.5%
- Forecast supported by customer growth that continues to trend above the national average
  - Our jurisdictions represent 3 of the top 5 states for net population migration in 2021(3)
  - Industry leader in economic development, enabling investment and job creation in our service territories

Cost management continues to be a core competency

BUSINESS TRANSFORMATION CONTINUES TO PRODUCE SUSTAINABLE COST SAVINGS…

($ IN BILLIONS)

O&M Cost Management(1)



COST MANAGEMENT ENABLES GREATER CAPITAL INVESTMENT

- $400 million in savings, 2016 – 2022
- Creates headroom for ~$3 billion of capital investment without increasing costs to customers(2)

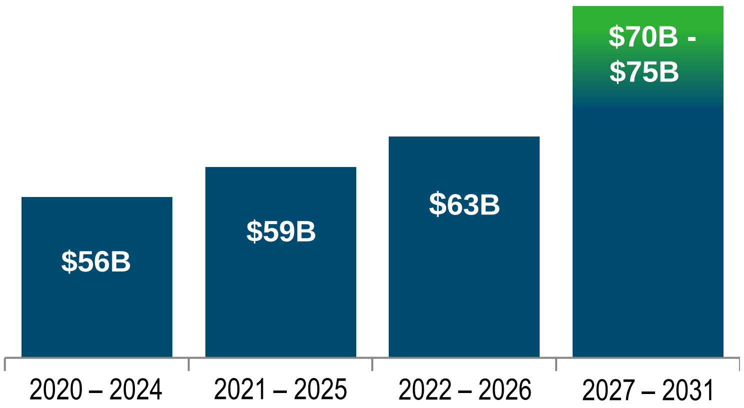
…EXPECT TO HOLD O&M FLAT THROUGH 2026

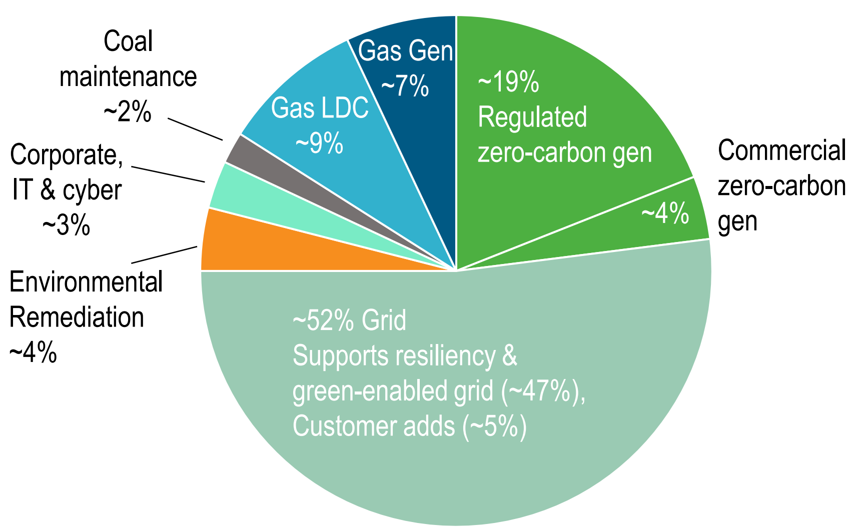
- ✓ **Digital innovation** efforts will increase operational efficiency while improving the customer experience
- ✓ **Energy transition from coal** to less O&M intensive generation
- ✓ Capital investments to **modernize the grid**, lowering ongoing maintenance costs
- – Near-term inflation pressure mitigated by **leveraging size and scale**

(1) *Proforma Net Regulated Gas O&M for Piedmont is presented to show combined Duke Energy and Piedmont Net Regulated Electric and Gas O&M for the full year 2016. Net regulated Electric and Gas O&M is a non-GAAP measure. For a description of this non-GAAP item and a reconciliation to GAAP O&M, see accompanying materials at www.duke-energy.com/investors*
(2) *Assumes every dollar of O&M reduction makes room for seven dollars of capex*

Robust capital plan to fund clean energy transition

$63B 5-YEAR PLAN…





… WITH $52 BILLION FUNDING FLEET TRANSITION AND GRID MODERNIZATION

HYDROGEN-ENABLED NATURAL GAS GENERATION

- Facilitates retirement of coal plants while maintaining affordability and reliability
- Hydrogen-enabled to further reduce CO_2 emissions as technology evolves

ZERO-CARBON GENERATION

- Regulated investments include nuclear, renewables, storage, and hydro
- Commercial renewables investments in wind and solar

TRANSMISSION AND DISTRIBUTION

- Grid investments to improve reliability and resiliency, including storm hardening
- Enables distributed generation resources
- Infrastructure to support customer growth

Projected growth over five-year plan

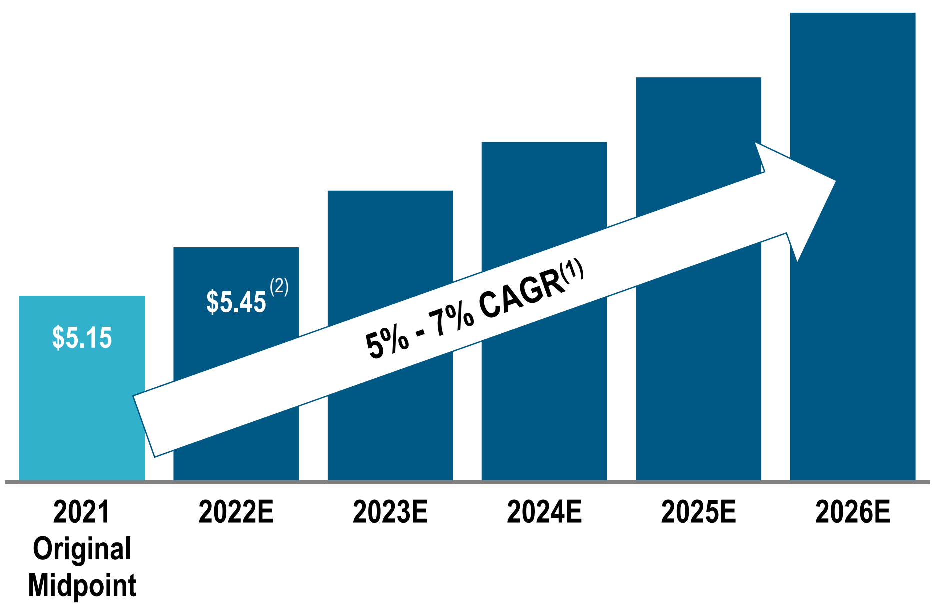
UPSIDES TO PLAN

- Acceleration of clean energy transition
- Robust service areas / economies
- Sustainable cost management
- Tax credits from federal legislation
- EV adoption

ITEMS TO MONITOR

- Inflation / rising interest rates
- Supply chain constraints
- Weather and storms

5-YEAR ADJUSTED EPS GROWTH PLAN



(1) Based off the midpoint of 2021 adjusted EPS guidance range ($5.15)
(2) Based off the midpoint of 2022 adjusted EPS guidance range of $5.30 - $5.60

Balance sheet supports our long-term growth strategy

COMMITTED TO MAINTAIN CURRENT CREDIT RATINGS

- Credit ratings recently affirmed at BBB/Baa2 (Stable)
- ~$1 billion tranche 2 closing of DEI minority interest sale to occur by Jan 2023
- Will continue issuing certain utility debt securities under Sustainable Financing Framework
- Targeting 14% FFO/Debt throughout the 5-year plan

FACTORS CONTRIBUTING TO BALANCE SHEET STRENGTH

- Pension plan 112% funded on a combined basis
- Operate in constructive jurisdictions
  - 3 states with above average RRA regulatory rankings, representing ~60% of earnings base
- Benefits from large size with diversity across regions, customers and fuel types
- Reduced regulatory lag from multi-year rate plans, riders and rate case timing
- Ongoing cost management and capital optimization

Our investor value proposition

DUK LISTED NYSE

A STRONG LONG-TERM RETURN PROPOSITION

DUK LISTED NYSE

3.8%

DIVIDEND YIELD(1) WITH LONG-TERM DIVIDEND **GROWTH COMMITMENT**(2)

~10%

ATTRACTIVE RISK-ADJUSTED **TOTAL SHAREHOLDER RETURN**(3)

5-7%

LONG-TERM **EPS GROWTH**(4) THROUGH 2026

CONSTRUCTIVE JURISDICTIONS, LOWER-RISK REGULATED INVESTMENTS AND BALANCE SHEET STRENGTH

(1) As of February 8, 2022
(2) Subject to approval by the Board of Directors.
(3) Total shareholder return proposition at a constant P/E ratio
(4) Based on adjusted EPS

APPENDIX

2021 enterprise accomplishments

CONTINUED OPERATIONAL EXCELLENCE

- Expect to be top decile in utility safety for the 7th consecutive year
- Delivered on goal to sustain $200M O&M cost savings identified in 2020
- 23rd consecutive year of nuclear capacity factor exceeding 90%, with a 2021 capacity factor of over 95%
- Self-optimizing grid capabilities helped avoid nearly 1.2 million hours of total outage time

SUPPORTING CUSTOMERS AND COMMUNITIES

- Top quartile J.D. Power & Associates' customer satisfaction index results for DE Carolinas, DE Progress, DE Florida, and Piedmont
- Customer rates remain below national average across all utilities
- New customer engagement platform (Customer Connect) implemented in the Carolinas and Florida
- Over $44 million in donations in support of our communities
- Dow Jones Sustainability Index North America: 16th consecutive year

EMPOWERING OUR EMPLOYEES

- Named to Fortune's Most Admired Companies for 5th consecutive year
- Named one of "America's Best Employers for Diversity" by Forbes in 2021 for 4th consecutive year
- Named to the Human Rights Campaign's 2022 list for "Best Place to Work for LGBTQ Equality"
- Employees/alumni volunteered more than 70,000 hours with nonprofits in our local communities

North Carolina clean energy legislation

ENGAGING WITH STAKEHOLDERS TO EXECUTE ENERGY LEGISLATION

- In October 2021, North Carolina enacted comprehensive clean energy legislation (HB 951)
  - Provides a framework to achieve 70% carbon reduction by 2030 against a 2005 baseline, and net-zero carbon emissions by 2050
  - Authorizes modernized regulatory recovery mechanisms (multi-year rate plans, revenue decoupling and performance incentive mechanisms)
- Rulemaking process for HB 951 is underway, with open dockets on performance-based regulation (PBR) and coal plant securitization
- Stakeholder engagement on the Carbon Plan ahead of May filing

2022 Timeline	Filed	Order required by	Docket #
Rulemaking for performance-based regulation	✓	February 10	E-100 Sub 178
Rulemaking for coal plant securitization	✓	April 11	E-100 Sub 177
Carbon Plan	May 16	December 31	E-100 Sub 179

Indiana integrated resource plan

TRANSITION TO CLEANER ENERGY WITH FOCUS ON RELIABILITY AND AFFORDABILITY

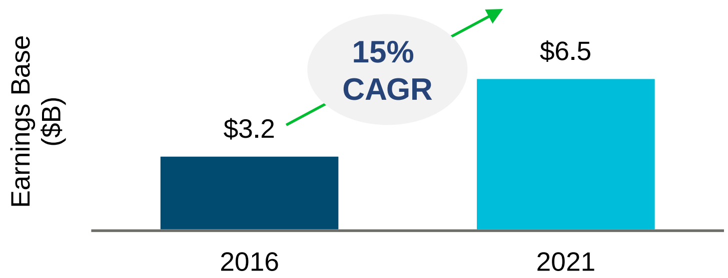
- Submitted 2021 Indiana integrated resource plan (IRP) in December
- Preferred portfolio reduces carbon emissions from our Indiana fleet by 63% in 2030 and 88% by 2040, compared to 2005 levels
- Key components of the company's preferred 20-year plan include:
  - Adds over 7,000 MW of renewables, plus 400 MW of energy storage
  - Adds 2,360 MW of natural gas, positioned to leverage hydrogen as the technology evolves
  - Accelerates coal plant retirement dates; retires all coal units by 2035(1)
- The Indiana Utility Regulatory Commission (IURC) does not approve the IRPs; rather, after receiving comments from stakeholders the staff of the IURC will issue a report on the plan

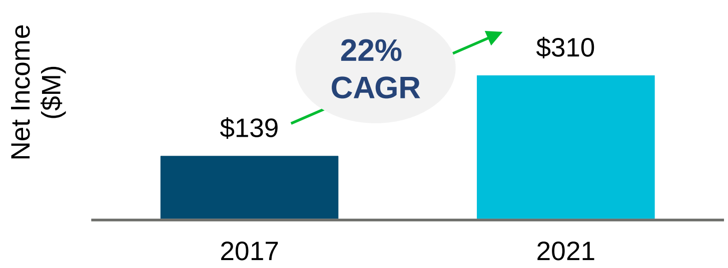
2022 Timeline	Status
IRP	✓
Request for proposal for new generation	February
IURC staff report on IRP	2022
CPCN filings	By year end 2022

(1) Contemplates retiring Edwardsport coal gasifiers by 2035 or adding carbon capture utilization and storage to reduce carbon emissions

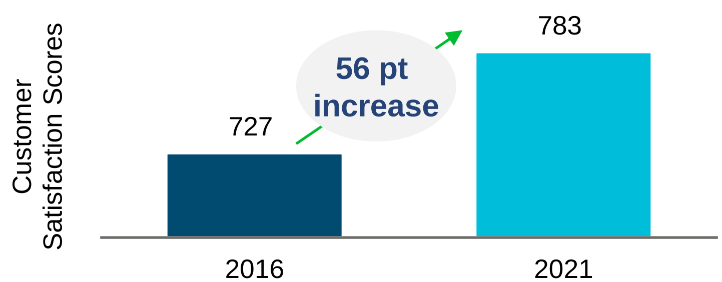
Piedmont update

2016 PIEDMONT ACQUISITION HAS BEEN GOOD FOR SHAREHOLDERS…





… AND GOOD FOR PIEDMONT CUSTOMERS



CONTINUED OPERATIONAL EXCELLENCE SUPPORTS GROWING CUSTOMER BASE

- Increased J.D. Power & Associates customer satisfaction score by 11 points in 2021, remain a top quartile performer
- Successfully placed in service the Robeson LNG facility for the benefit of Piedmont Carolina customers in 2021
- Constructive rate case outcomes in North Carolina and Tennessee
- Achieved top decile OSHA TICR safety performance within AGA peer group in 2020
- Strong residential customer growth since 2016, 1.9% CAGR

Alternative technology partnerships and investments

HYDROGEN

- Partnering with Siemens and Clemson University on a Department of Energy supported study to evaluate hydrogen integration and utilization at the Duke owned and operated Clemson combined heat and power plant
- The pilot project began in March 2021 and includes studies on hydrogen production, storage and co-firing with natural gas
- Evaluating 30% co-firing of hydrogen in 2024 and 100% firing of hydrogen on or before 2030

ADVANCED NUCLEAR

- Partnering with TerraPower and the Natrium Reactor team. Duke Energy's role is to provide consulting and advisory in-kind services
- The Natrium plant is designed with integrated thermal storage with a steady state electrical output of 345 MW that can increase to 500 MW utilizing stored energy
- The project is targeting to be operational within 7 years (by 2028)

ENERGY STORAGE

- Testing Honeywell's new flow battery technology, which can store and discharge electricity for up to 12 hours, exceeding the duration of lithium-ion batteries, which can only discharge up to 4 hours
- Honeywell will deliver a 400-kilowatt-hour (kWh) unit to Duke Energy's Emerging Technology and Innovation Center in Mount Holly, N.C. in 2022
- Will begin testing EOS Znyth Gen 3.0 battery (zinc bromine) in late 2022

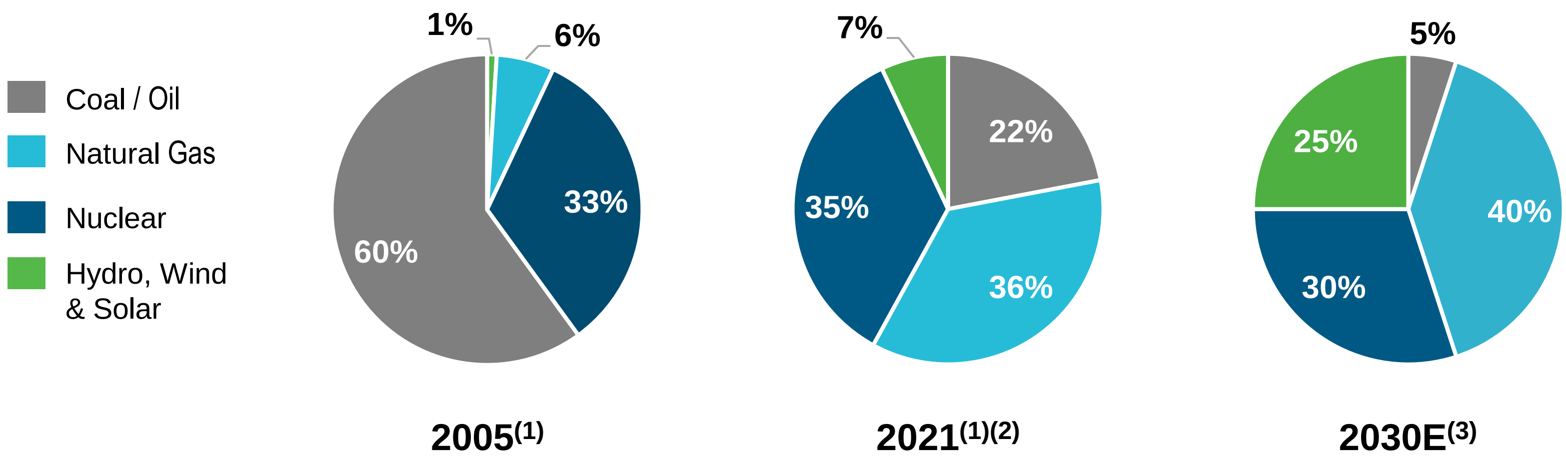
DUKE ENERGY VENTURES

- Duke Energy has an established corporate venture capital effort including investments in VC funds managed by Energy Impact Partners and The Westly Group
- Duke Energy leverages VC investing to stay current on new and innovative technology and foster interactions between Duke Energy subject matter experts and start-up companies

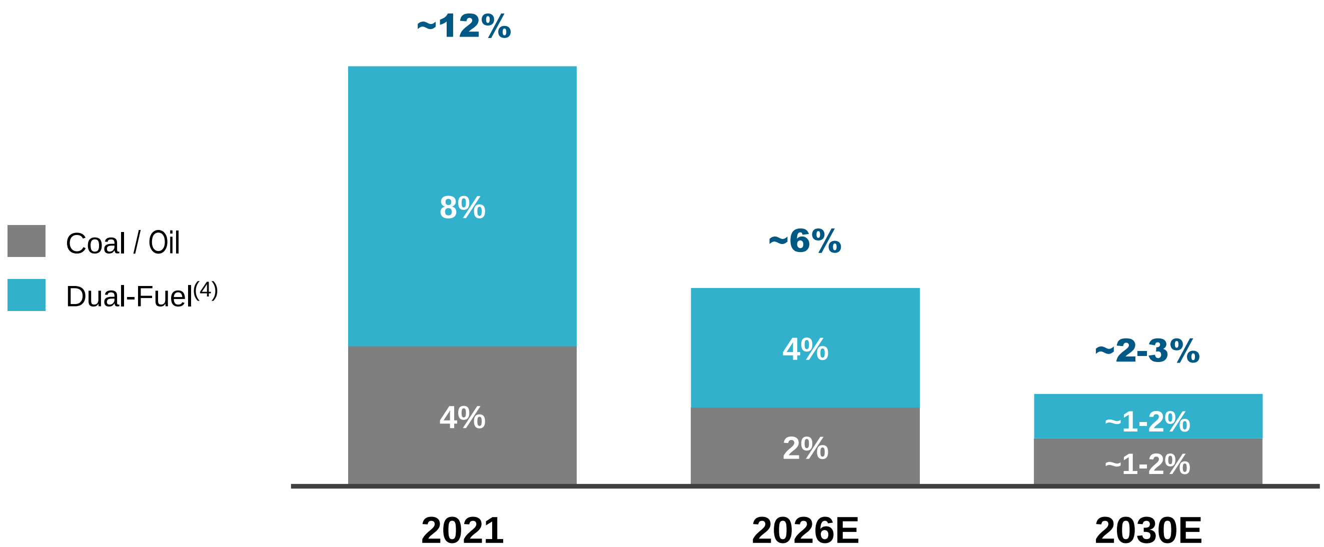
SUSTAINABILITY / ENVIRONMENTAL SOCIAL AND GOVERNANCE (ESG)

Transforming the way we produce power

Generation (MWh) by Fuel Type



Coal as a % of Earnings Base

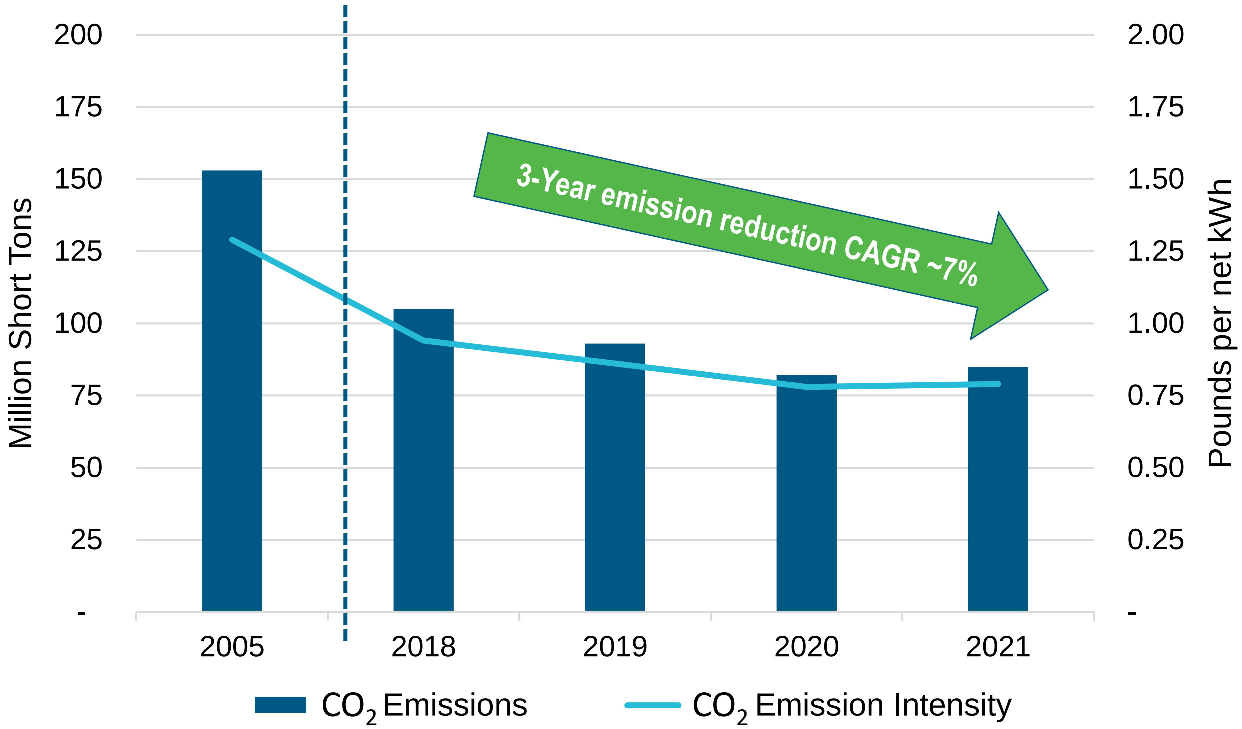


(1) 2005 and 2021 data based on Duke's ownership share of U.S. generation assets as of Dec. 31, 2021.
(2) 2021 data excludes 9,088 GWh of purchased renewables, equivalent to ~4% of Duke's output.
(3) 2030 estimate will be influenced by customer demand for electricity, weather, fuel and purchased power prices, and other factors.
(4) As of December 31, 2021, the dual-fuel capable units and percentage of gas capacity are Cliffside 6 (100%), Belews Creek 1 & 2 (50%), Cliffside 5 (40%) Marshall 1&2 (40%), Marshall 3&4 (50%), Edwardsport (100%).

Significantly reducing GHG emissions on our journey toward net-zero

EMISSIONS FROM ELECTRIC GENERATION

CO_2 Emissions (million short tons) and Emission Intensity (Lbs/net kWh)

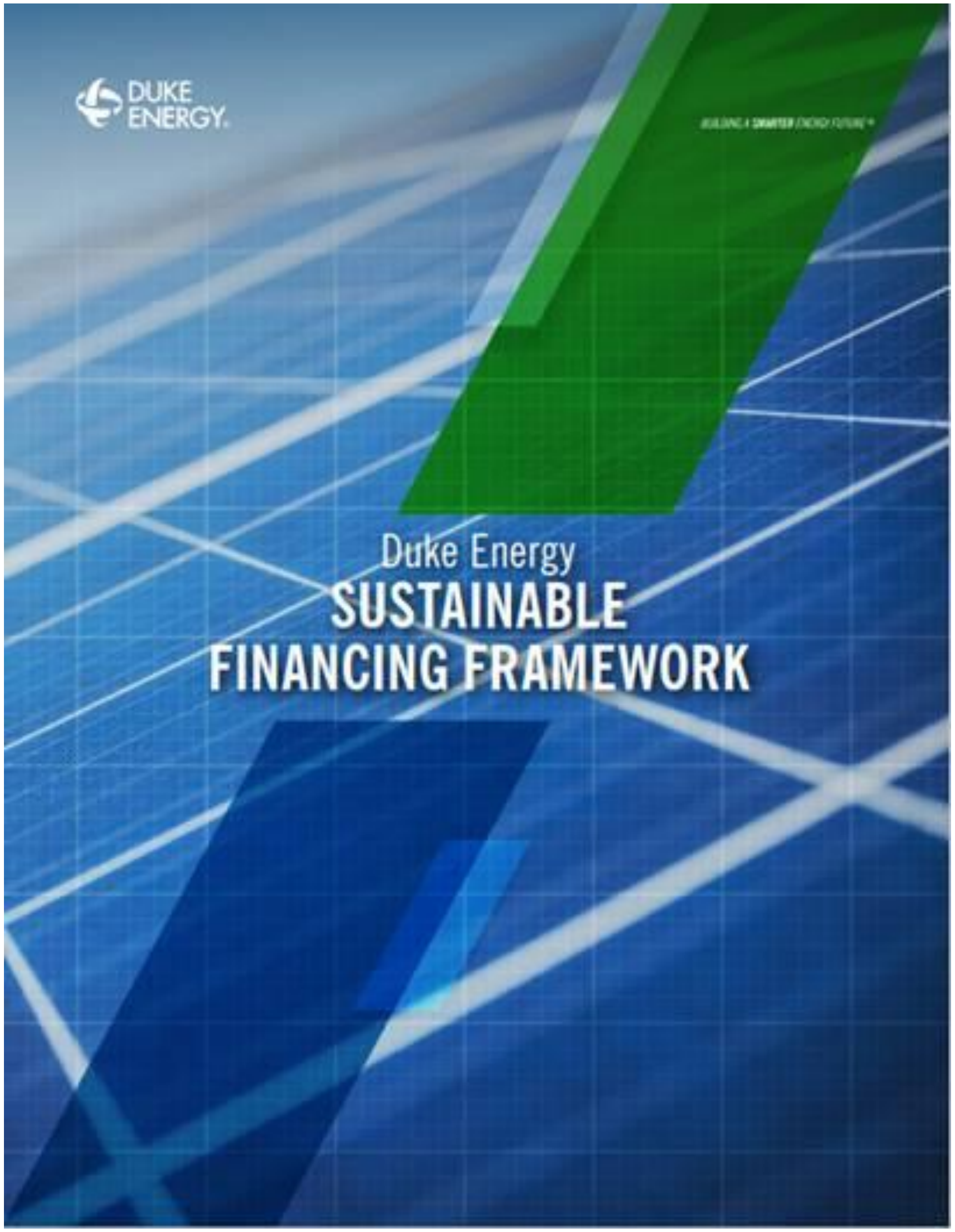


KEY MESSAGES

- 44% reduction to CO_2 emissions since 2005
- On track to exceed 50% reduction by 2030
- 39% reduction in CO_2 intensity since 2005
- Pace of change will continue to accelerate over the next decade

Removed 68 million short tons of annual CO_2 emissions since 2005, equivalent to taking over 13 million fossil-fueled vehicles off the road

Recently published sustainable financing framework



sustainable-financing-framework

- Previously issued green bonds financed renewable energy and battery storage investments
- New use of proceeds-based framework greatly expands the eligible project categories to align with our goals of net-zero carbon emissions by 2050:
  - Renewable energy
  - Green innovation
  - Energy efficiency
  - Clean transportation
  - Green buildings
  - Climate change adaptation
  - Socio-economic advancement & empowerment
- External review of the framework by S&P Global and opinion published on their platform
- Independent public accounting firm verification of each Sustainable Financing under the framework

North Carolina subcritical coal generation[1]

NC CLEAN ENERGY LEGISLATION PROVIDES FOR THE SECURITIZATION OF 50% OF THE BALANCE OF SUBCRITICAL COAL GENERATION AT RETIREMENT

Coal securitization rulemaking to be completed by April 11, 2022

($ in millions)		Net Book Value 12/31/21		Annual Depreciation[2]	Depreciation Study Retirement Date[2]	Earliest Practicable Retirement Date[3]
		System	NC Retail	NC Retail		
DEC	Allen 1&5	$289	$193	$8	2026	2023
	Allen 2-4[4]	105	70	9	Retired	Retired
	Cliffside 5	365	245	20	2032	2025
	Marshall 1-2	454	304	24	2034	2027
DEP	Mayo	631	391	26	2035	2025
	Roxboro 1-2	773	479	45	2028	2027
	Roxboro 3-4	457	283	23	2033	2027
	TOTAL	$3,074	$1,965	$155		

(1) Amounts provided herein are for informational purposes only. The actual retirement dates for coal generation are to be determined in accordance with the Carbon Plan, which will be filed in May 2022. Additionally, changes in depreciation rates and capital additions prior to the retirement of the units could affect remaining net book values.
(2) Per most recent depreciation studies. Units would retire by December 31st of year listed.
(3) Per Carolinas IRPs filed September 2020. Units would retire by December 31st of year listed.
(4) Allen 2-4 units retired in 2021. In accordance with the Order issued in the 2019 North Carolina Rate Case, the retail NBV of Allen Unit 4 ($47 million) was reclassified as a regulatory asset, with $9 million of amortization annually.

Long-standing history of strong governance driven from diverse Board of Directors

FOCUSED ON BOARD COMPOSITION TO OVERSEE THE COMPANY'S LONG-TERM STRATEGY

- 13 out of 14 directors are independent (all directors except Chair, President and CEO)
- 6 out of 14 directors are female or identify as a part of a minority group

Board of Directors

Lynn J. Good
Chair, President & CEO, Duke Energy
Director since 2013

Michael G. Browning
Independent Lead Director
Principal, Browning Consolidated
Director since 2006

Annette K. Clayton
President & CEO, North America Operations, Schneider Electric
Director since 2019

Theodore F. Craver Jr.
Retired Chairman, President, & CEO, Edison International
Director since 2017

Robert M. Davis
President and CEO, Merck & Co.
Director since 2018

Caroline Dorsa
Retired Executive Vice President & CFO, PSEG
Director since 2021

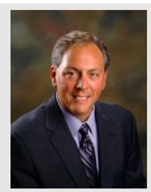
W. Roy Dunbar
Retired Chairman and CEO, Network Solutions
Director since 2021

Nicholas C. Fanandakis
Retired EVP, DuPont de Nemours
Director since 2019

John T. Herron
Retired President, CEO & Chief Nuclear Officer, Entergy Nuclear
Director since 2013

Idalene F. Kesner
Dean, Indiana University Kelley School of Business
Director since 2021

E. Marie McKee
Retired SVP, Corning
Director since 2012



Michael J. Pacilio
Retired Executive Vice President & COO, Exelon Generation
Director since 2021

Thomas E. Skains
Retired Chairman, President & CEO, Piedmont Natural Gas
Director since 2016

William E. Webster
Retired EVP, Institute of Nuclear Power Operations
Director since 2016

Key Stats

43%
Racial, Gender and Ethnic Diversity

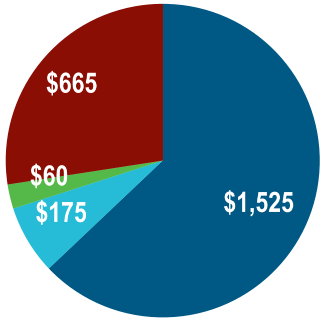
4.4
Years Average Tenure

2021 PERFORMANCE AND 2022 GUIDANCE SUPPLEMENTAL INFORMATION

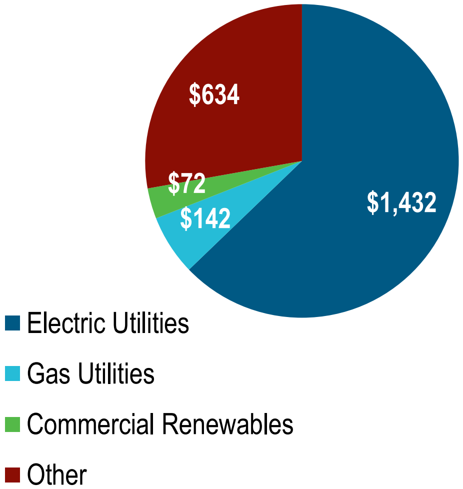
Key 2022 adjusted earnings guidance assumptions

($ in millions)	Original 2021 Assumptions	2021 Actual	2022 Assumptions
Adjusted segment income/(expense)(1):			
Electric Utilities & Infrastructure	$3,900	$3,919	$4,170
Gas Utilities & Infrastructure	$415	$411	$470
Commercial Renewables	$220	$201	$150
Other	($575)	($504)	($595)
Duke Energy Consolidated	$3,960	$4,027	$4,195
Additional consolidated information:			
Effective tax rate including noncontrolling interests and preferred dividends and excluding special items	6-8%	6.0%	8-10%
AFUDC equity	$185	$171	$195
Capital expenditures (2)(3)	$10,475	$9,590	$12,350
Weighted-average shares outstanding – basic	~769 million	~769 million	~770 million

2022 Interest Expense Assumptions
(Consolidated Total $2,425)



2021 Interest Expense
(Consolidated Total $2,280)



(1) *Adjusted net income for 2022 assumptions is based upon the midpoint of the adjusted EPS guidance range of $5.30 to $5.60*
(2) *Includes debt AFUDC and capitalized interest*
(3) *2021 actual includes coal ash closure spend of ~$444 million that was included in operating cash flows. 2022 Assumptions include ~$488 million of projected coal ash closure spend.*

Electric utilities quarterly weather impacts

Weather segment income to normal:	2021			2020		
	Pretax impact	Weighted avg. shares	EPS impact favorable / (unfavorable)	Pretax impact	Weighted avg. shares	EPS impact favorable / (unfavorable)
First Quarter	($17)	769	($0.02)	($110)	734	($0.11)
Second Quarter	$7	769	$0.01	($8)	735	($0.01)
Third Quarter	$46	769	$0.05	$67	735	$0.07
Fourth Quarter	(81)	769	($0.08)	$2	742	--
Year-to-Date[(1)]	(46)	769	($0.05)	($48)	737	($0.05)

4Q 2021	**Duke Energy Carolinas**		**Duke Energy Progress**		**Duke Energy Florida**		**Duke Energy Indiana**		**Duke Energy Ohio/KY**	
Heating degree days / Variance from normal	967	(21.7%)	855	(23.1%)	84	(55.4%)	1,639	(16.0%)	1,474	(19.0%)
Cooling degree days / Variance from normal	79	87.9%	106	68.6%	584	20.3%	46	131.3%	61	170.8%

4Q 2020	**Duke Energy Carolinas**		**Duke Energy Progress**		**Duke Energy Florida**		**Duke Energy Indiana**		**Duke Energy Ohio/KY**	
Heating degree days / Variance from normal	1,098	(12.1%)	933	(17.1%)	207	1.8%	1,822	(7.6%)	1,671	(9.0%)
Cooling degree days / Variance from normal	51	25.7%	91	50.0%	624	41.0%	19	9.1%	21	(4.0%)

(1) Year-to-date amounts may not foot due to differences in weighted-average shares outstanding and/or rounding.

Key 2022 earnings sensitivities

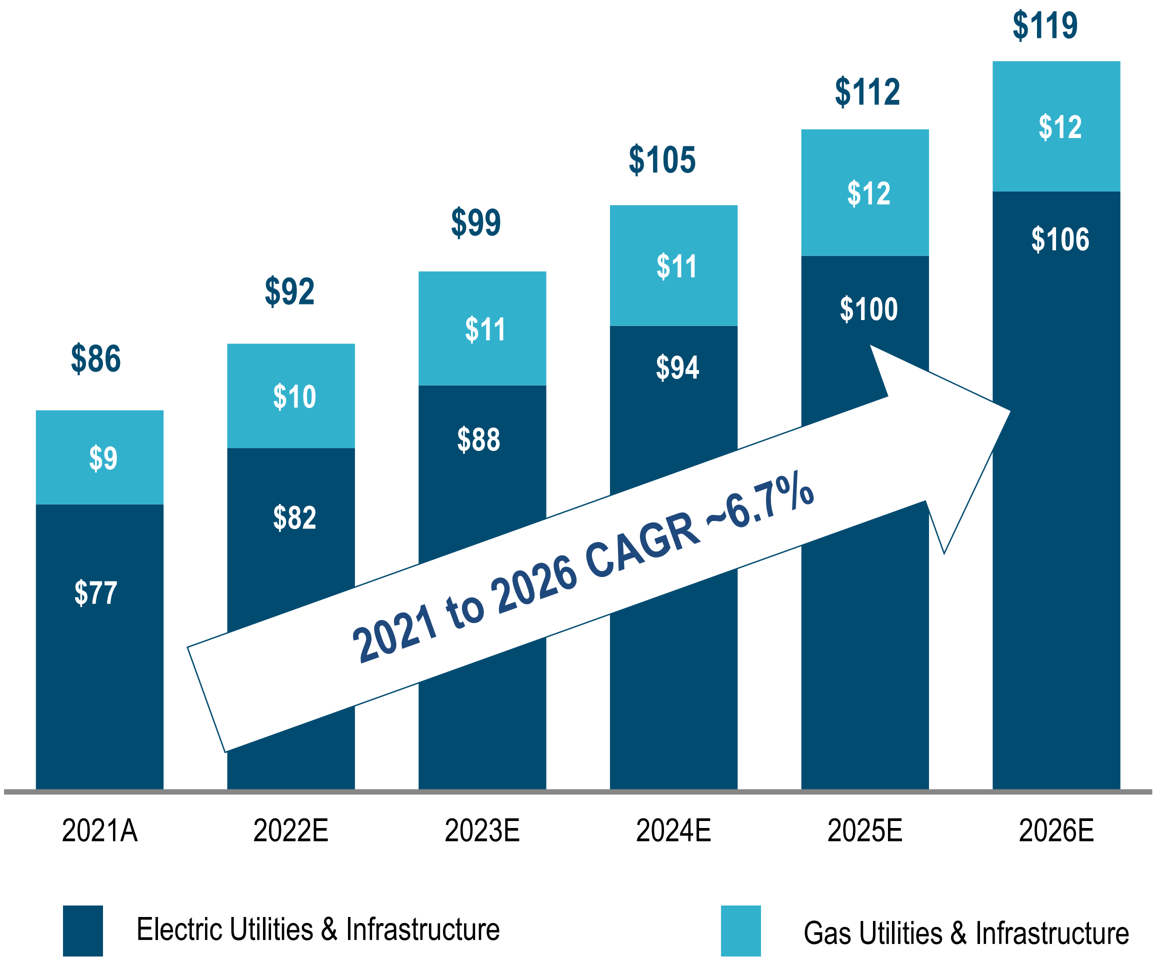
Driver		EPS Impact
Electric Utilities & Infrastructure	1% change in earned return on equity	+/- $0.53
	$1 billion change in rate base	+/- $0.07
	1% change in Electric Utilities volumes Industrial +/- $0.02 (2) Commercial +/- $0.05 (2) Residential +/- $0.08 (2)	+/- $0.15(1) (2)
Gas Utilities & Infrastructure	1% change in earned return on equity	+/- $0.08
	$200 million change in rate base	+/- $0.01
	1% change in number of new customers	+/- $0.02
Consolidated	1% change in interest rates(3)	+/- $0.12

Note: EPS amounts based on forecasted 2022 basic share count of ~770 million shares

(1) Assumes 1% change across all customer classes; EPS impact for the industrial class is lower due to lower margins
(2) Margin sensitivities are mitigated by the fixed component portion of bills, resulting in lower impacts to earnings than depicted.
(3) Based on average variable-rate debt outstanding throughout the year and new issuances.

Earnings base growth

2022-2026 REGULATED ELECTRIC AND GAS EARNINGS BASE(1)(2)



(1) *In billions. Illustrative earnings base for presentation purposes only and includes retail and wholesale; Amounts as of the end of each year shown; Projected earnings base = prior period earnings base + capex – D&A – deferred taxes – securitized assets. Totals may not foot due to rounding*

(2) *Amounts presented gross of GIC 19.9% minority investment and earnings base is presented net of coal ash settlement.*

Regulated utilities end of year earnings base[1]

Electric Utilities Earnings Base

($ in billions)	2021A	2022E	2023E	2024E	2025E	2026E
Duke Energy Carolinas[2]	$28.1	$30.2	$32.9	$34.6	$36.9	$38.9
Duke Energy Progress[2]	18.2	19.6	20.7	22.3	24.4	26.2
Duke Energy Florida	16.5	17.7	19.1	20.7	22.1	23.0
Duke Indiana	9.5	9.8	10.3	10.7	11.3	12.2
Duke Ohio – Electric	3.5	3.7	3.9	4.0	4.2	4.5
Duke Kentucky – Electric	1.1	1.2	1.3	1.3	1.4	1.5
Electric Utilities Total[3][4]	**$76.9**	**$82.2**	**$88.1**	**$93.7**	**$100.3**	**$106.3**

Gas Utilities Earnings Base

($ in billions)	2021A	2022E	2023E	2024E	2025E	2026E
Piedmont	$6.5	$7.2	$7.9	$8.3	$8.7	$9.0
Duke Energy Ohio – Gas	1.8	2.0	2.2	2.3	2.4	2.4
Duke Energy Kentucky - Gas	0.5	0.6	0.7	0.7	0.8	0.8
Gas Utilities Total[3]	**$8.8**	**$9.8**	**$10.7**	**$11.3**	**$11.8**	**$12.2**

($ in billions)	2021A	2022E	2023E	2024E	2025E	2026E
Total Company[3][4]	**$85.8**	**$92.0**	**$98.8**	**$105.0**	**$112.1**	**$118.5**

(1) Illustrative earnings base for presentation purposes only and includes retail and wholesale; Amounts as of the end of each year shown; Projected earnings base = prior period earnings base + capex – D&A – deferred taxes – securitized assets.
(2) Amounts presented are net of 2021 North Carolina, South Carolina coal ash settlements
(3) Totals may not foot due to rounding
(4) Amounts presented gross of GIC 19.9% minority investment (~11% as of Q2 2021; 19.9% as of Jan. 2023)

Capital expenditures profile(1)

($ in millions)

Capital Expenditures	2021A	2022E	2023E	2024E	2025E	2026E	2022 - 2026
Electric Generation(2)	1,157	1,475	1,900	2,225	2,750	3,650	12,000
Electric Transmission	883	1,425	1,350	1,450	1,325	1,425	6,975
Electric Distribution	2,255	3,325	3,625	3,675	3,800	3,800	18,225
Environmental & Other(3)	767	775	575	475	425	375	2,625
Electric Utilities & Infrastructure Growth Capital	**$5,062**	**$7,000**	**$7,450**	**$7,825**	**$8,300**	**$9,250**	**$39,825**
Maintenance	3,036	2,950	3,050	2,600	2,500	2,300	13,400
Total Electric Utilities & Infrastructure Capital(4)	**$8,098**	**$9,950**	**$10,500**	**$10,425**	**$10,800**	**$11,550**	**$53,225**
Commercial Renewables(5)	(45)	600	800	400	500	250	2,550
Total Commercial Renewables Capital	**($45)**	**$600**	**$800**	**$400**	**$500**	**$250**	**$2,550**
Renewables Natural Gas	40	75	100	75	25	-	275
LDC - Non-Rider	236	350	375	325	300	250	1,600
LDC - Rider	342	525	575	450	450	325	2,325
Gas Utilities & Infrastructure Growth Capital	**$618**	**$950**	**$1,050**	**$850**	**$775**	**$575**	**$4,200**
Maintenance	632	400	325	300	250	300	1,575
Total Gas Utilities & Infrastructure Capital	**$1,251**	**$1,350**	**$1,375**	**$1,150**	**$1,025**	**$875**	**$5,775**
Other(6)	287	450	300	250	225	200	1,425
Total Duke Energy	**$9,590**	**$12,350**	**$12,975**	**$12,225**	**$12,550**	**$12,875**	**$62,975**

(1) Amounts include AFUDC debt or capitalized interest. Totals may not foot due to rounding
(2) Includes nuclear fuel of ~$2.2B from 2022-2026
(3) 2021 actual amounts include ~$444 million in coal ash closure spending that was included in operating cash flows
(4) Capex amounts are presented gross of GIC minority investment (~11% as of Q3 2021; 19.9% as of Jan. 2023)
(5) Amounts are net of assumed tax equity financings
(6) Primarily IT and real estate related costs

Capital expenditures by utility (continued)[1]

($ in millions)

Duke Energy Carolinas	2021A	2022E	2023E	2024E	2025E	2026E	2022 - 2026
Electric Generation	406	475	625	725	900	1,425	4,150
Electric Transmission	95	300	350	325	275	225	1,475
Electric Distribution	851	1,150	1,450	1,175	1,200	1,125	6,100
Environmental & Other[2]	409	475	250	225	200	200	1,350
Electric Utilities & Infrastructure Growth Capital	**$1,760**	**$2,400**	**$2,675**	**$2,450**	**$2,575**	**$2,975**	**$13,075**
Maintenance	1,115	1,200	1,300	925	950	925	5,300
Total Duke Energy Carolinas	**$2,875**	**$3,600**	**$3,975**	**$3,375**	**$3,525**	**$3,900**	**$18,375**

Duke Energy Progress	2021A	2022E	2023E	2024E	2025E	2026E	2022 - 2026
Electric Generation	179	475	525	825	1,075	1,200	4,100
Electric Transmission	56	175	150	200	300	275	1,100
Electric Distribution	496	925	850	950	1,050	1,075	4,850
Environmental & Other[3]	235	175	175	150	125	125	750
Electric Utilities & Infrastructure Growth Capital	**$966**	**$1,750**	**$1,700**	**$2,125**	**$2,550**	**$2,675**	**$10,800**
Maintenance	966	850	775	725	575	625	3,550
Total Duke Energy Progress	**$1,932**	**$2,600**	**$2,475**	**$2,850**	**$3,125**	**$3,300**	**$14,350**

(1) Amounts include AFUDC debt. Totals may not foot due to rounding
(2) 2021 actual amounts include ~$182 million in coal ash closure spending that was included in operating cash flows
(3) 2021 actual amounts include ~$192 million in coal ash closure spending that was included in operating cash flows

Capital expenditures by utility (continued)[1]

($ in millions)

Duke Energy Florida	2021A	2022E	2023E	2024E	2025E	2026E	2022 - 2026
Electric Generation	527	500	550	475	475	350	2,350
Electric Transmission	436	650	575	600	475	525	2,825
Electric Distribution	434	700	800	975	900	975	4,350
Environmental & Other[2]	31	-	-	-	-	-	
Electric Utilities & Infrastructure Growth Capital	**$1,429**	**$1,850**	**$1,925**	**$2,050**	**$1,850**	**$1,850**	**$9,525**
Maintenance	494	400	475	500	525	375	2,275
Total Duke Energy Florida	**$1,923**	**$2,250**	**$2,400**	**$2,550**	**$2,375**	**$2,225**	**$11,800**

Duke Energy Indiana	2021A	2022E	2023E	2024E	2025E	2026E	2022 - 2026
Electric Generation	41	25	125	200	275	650	1,275
Electric Transmission	160	150	125	200	175	250	900
Electric Distribution	242	275	250	275	325	300	1,425
Environmental & Other[3]	80	100	150	100	75	50	475
Electric Utilities & Infrastructure Growth Capital	**$523**	**$550**	**$650**	**$775**	**$850**	**$1,250**	**$4,075**
Maintenance	361	400	375	325	325	250	1,675
Total Duke Energy Indiana[4]	**$884**	**$950**	**$1,025**	**$1,100**	**$1,175**	**$1,500**	**$5,750**

(1) Amounts include AFUDC debt. Totals may not foot due to rounding
(2) 2021 actual amounts include ~$1 million in coal ash closure spending that was included in operating cash flows
(3) 2021 actual amounts include ~$66 million in coal ash closure spending that was included in operating cash flows
(4) DEI capex presented gross of GIC minority investment (~11% as of Q3 2021; 19.9% as of Jan. 2023)

Capital expenditures by utility (continued)[1]

($ in millions)

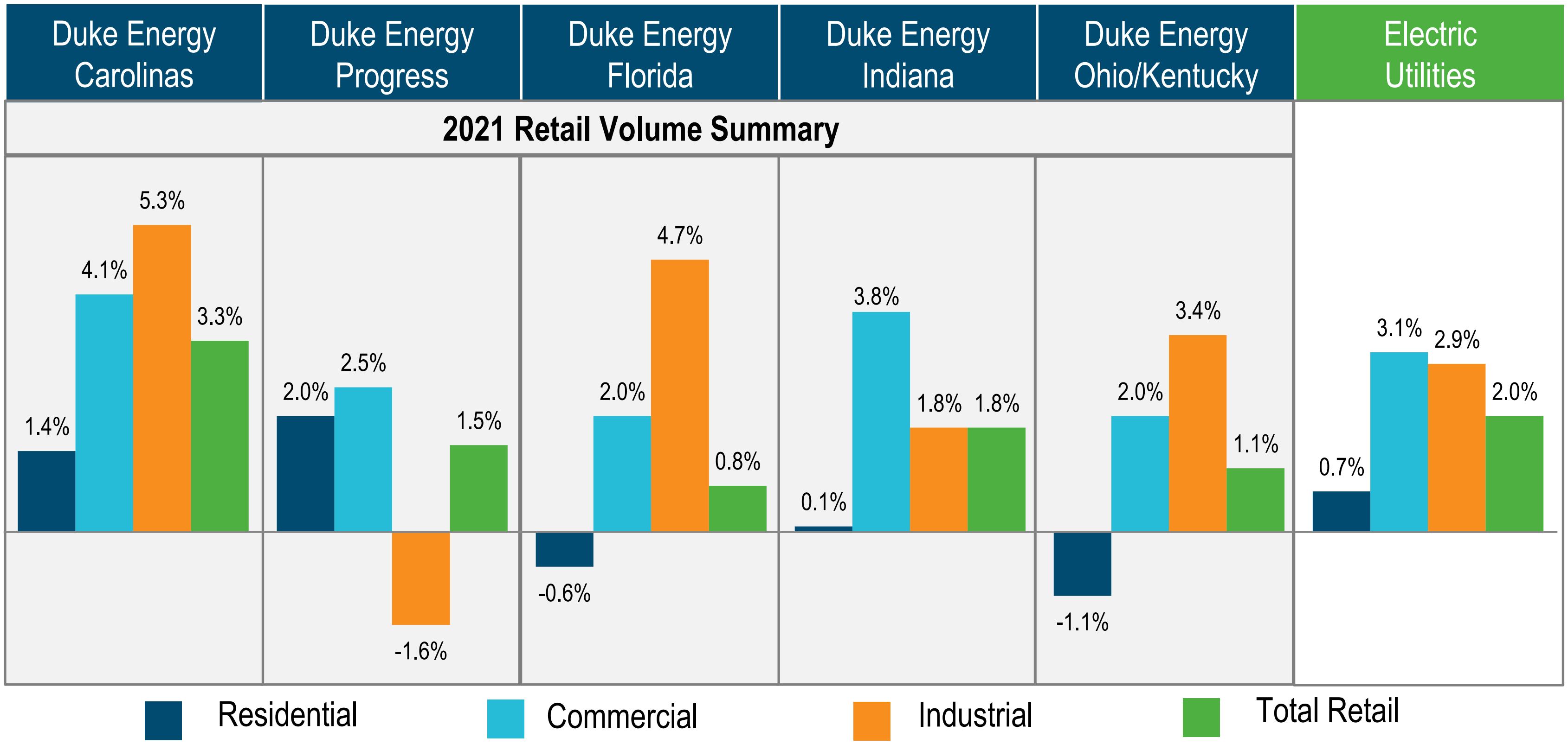
Duke Energy OH/KY Electric	2021A	2022E	2023E	2024E	2025E	2026E	2022 - 2026
Electric Generation	4	-	75	-	25	25	125
Electric Transmission	137	125	150	150	125	125	675
Electric Distribution	237	225	250	225	225	250	1,175
Environmental & Other[2]	11	25	-	-	-	-	25
Electric Utilities & Infrastructure Growth Capital	**$388**	**$375**	**$475**	**$375**	**$375**	**$400**	**$2,000**
Maintenance	100	100	125	125	125	125	600
Total DEO/DEK Electric	**$488**	**$475**	**$600**	**$500**	**$500**	**$525**	**$2,600**

Duke Energy OH/KY Gas	2021A	2022E	2023E	2024E	2025E	2026E	2022 - 2026
LDC - Non-Rider	48	75	75	75	100	50	375
LDC - Rider	-	25	50	50	25	25	175
Gas Utilities & Infrastructure Growth Capital	**$48**	**$100**	**$125**	**$125**	**$125**	**$75**	**$550**
Maintenance	314	200	200	175	150	150	875
Total DEO/DEK Gas	**$362**	**$300**	**$325**	**$300**	**$275**	**$225**	**$1,425**

Piedmont	2021A	2022E	2023E	2024E	2025E	2026E	2022 - 2026
LDC - Non-Rider	189	300	300	250	200	200	1,250
LDC - Rider	342	500	525	400	400	300	2,125
Gas Utilities & Infrastructure Growth Capital	**$530**	**$800**	**$825**	**$650**	**$600**	**$500**	**$3,375**
Maintenance	318	200	125	125	125	150	725
Total Piedmont Gas	**$848**	**$1,000**	**$950**	**$775**	**$725**	**$650**	**$4,100**

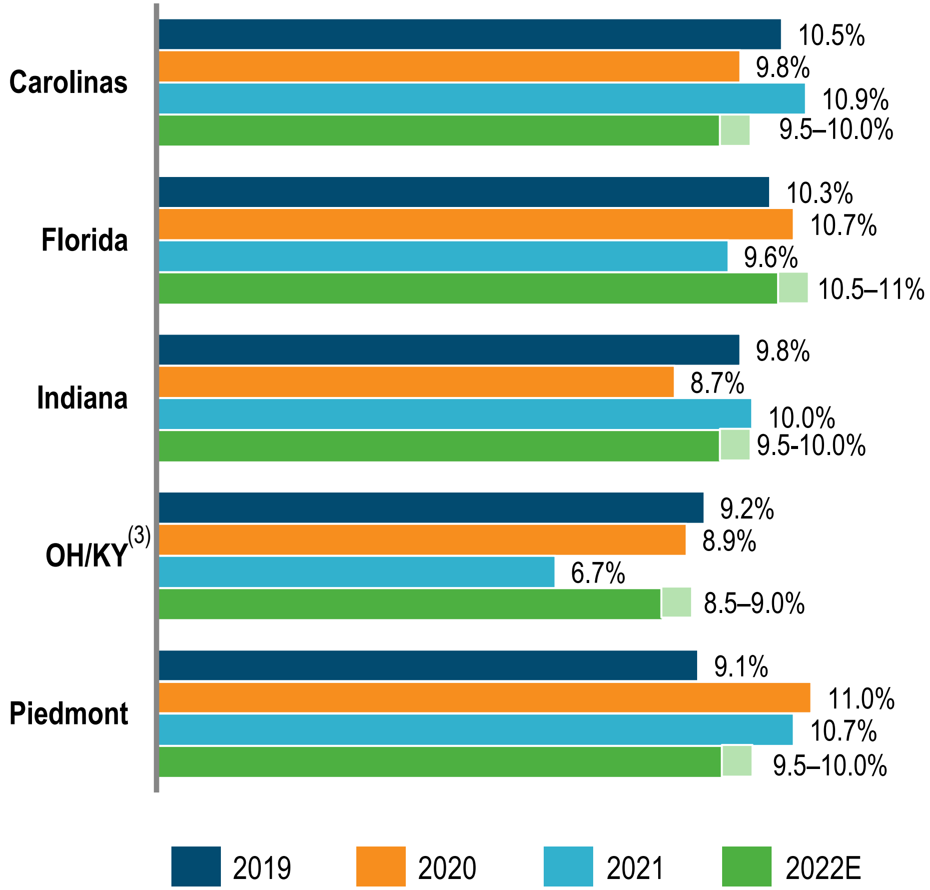
(1) *Amounts include AFUDC debt. Totals may not foot due to rounding*
(2) *2021 actual amounts include ~$2 million in coal ash closure spending that was included in operating cash flows*

Weather normalized volume trends, by electric jurisdiction

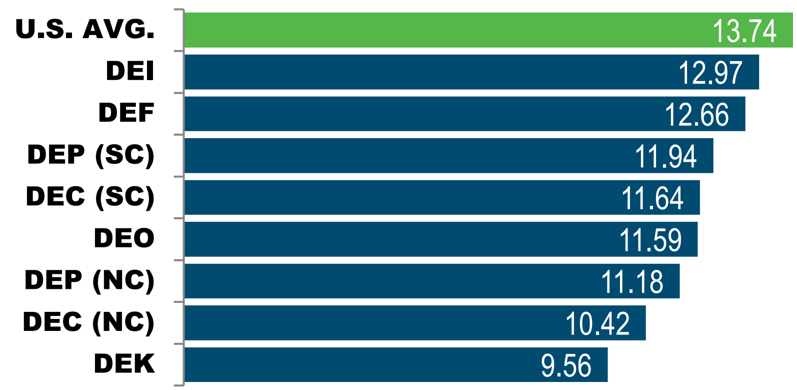


Managing regulatory lag and customer rate impacts

ADJUSTED BOOK ROEs(1)



COMPETITIVE CUSTOMER RATES(2)



DELIVERING COMPETITIVE RETURNS FOR INVESTORS WHILE KEEPING RATES WELL BELOW THE NATIONAL AVERAGE FOR CUSTOMERS

(1) *Adjusted book ROEs exclude special items and are based on average book equity less Goodwill. Adjusted ROEs also include wholesale and are not adjusted for the impacts of weather. Regulatory ROEs will differ from Adjusted Book ROEs*
(2) *Residential customer rates. Typical bill rates (¢/kWh) in effect as of January 1, 2021. Source: EEI Typical Bills and Avg. Rates Report, Winter 2021*
(3) *Combined electric and gas utilities*

FINANCING PLAN UPDATE AND CURRENT LIQUIDITY

2022 Financing plan[1]

Issuer	Estimated Amount ($ in millions)	Security	Date Issued	Completed ($ in millions)	Term	Rate	2022 Maturities[2]
Holding Company	$5,500 - $6,000	Senior Debt / Hybrid Securities	-	-	-	-	$2,050 (May, Apr. & Aug.)
DE Carolinas	$1,000 – 1,300	Senior Debt	-	-	-	-	$350 (May)
DE Progress	$1,200 - $1,400	Senior Debt	-	-	-	-	$500 (May)
DE Florida	$400 - $600	Senior Debt	-	-	-	-	-
DE Indiana	$50 - $75	Tax-Exempt Debt	-	-	-	-	-
Piedmont	$300 - $500	Senior Debt	-	-	-	-	-
DE Kentucky	$40 - $60	Tax-Exempt Debt	-	-	-	-	-

(1) Excludes financings at Commercial Renewables and other non-regulated entities
(2) Excludes amortization of noncash purchase accounting adjustments and securitization bonds

Liquidity summary (as of December 31, 2021)

($ in millions)

	Duke Energy	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio	Duke Energy Kentucky	Piedmont Natural Gas	Total
Master Credit Facility (1)	$ 2,650	$ 1,225	$ 1,150	$ 900	$ 600	$ 600	$ 175	$ 700	$ 8,000
Less: Notes payable and commercial paper (2)	(1,128)	(506)	(307)	(181)	(150)	-	(119)	(472)	$ (2,863)
Outstanding letters of credit (LOCs)	(25)	(4)	(2)	(7)	-	-	-	-	(38)
Tax-exempt bonds	-	-	-	-	(81)	-	-	-	(81)
Available capacity	$ 1,497	$ 715	$ 841	$ 712	$ 369	$ 600	$ 56	$ 228	$ 5,018
Funded Revolver and Term Loan (3)	$ 1,000								$ 1,000
Less: Borrowings Under Credit Facilities	(500)								(500)
Available capacity	$ 500	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 500
Cash & short-term investments									271
Total available liquidity									**$ 5,789**

(1) Duke Energy's master credit facility supports Tax-Exempt Bonds, LOCs and the Duke Energy CP program of $6 billion.
(2) Includes permanent layer of commercial paper of $625 million, which is classified as long-term debt
(3) Borrowings under these facilities will be used for general corporate purposes.

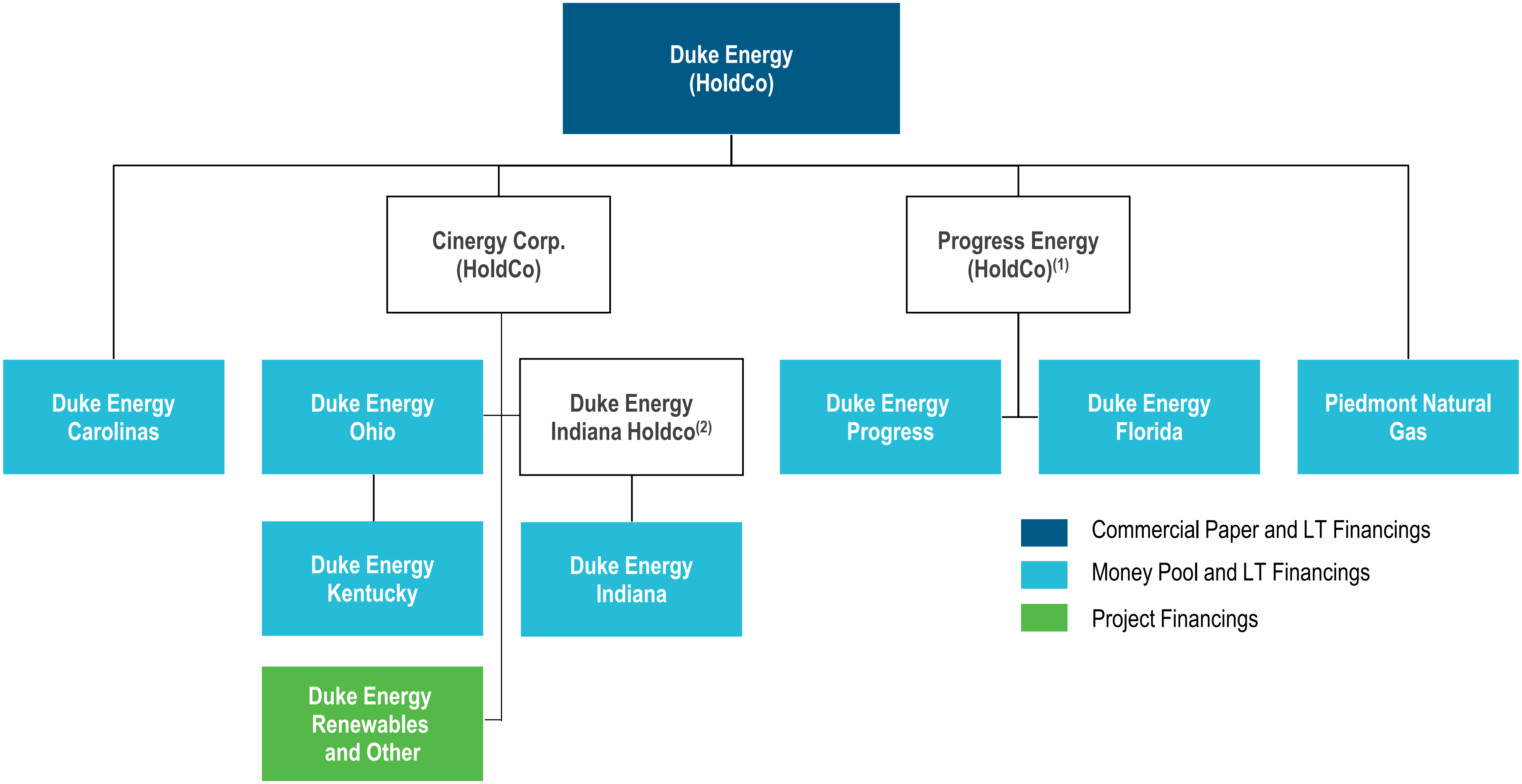
2022 Pension funding and costs

- On a consolidated basis, the Duke Energy pension plan was fully funded as of 12/31/2021 on a PBO basis
- Duke Energy's pension funding policy:
  - Duke Energy's policy is to fund amounts on an actuarial basis to provide assets sufficient to meet benefit payments to be paid to plan participants
- On a consolidated basis, the plan has a target asset allocation of 40% return-seeking assets and 60% liability hedging assets

Pension Contributions *($ in millions)*	2020A	2021A	2022E
All plans	$0	$0	~$5M to ~$20M

- Key 2022 assumptions:
  - Discount rate: 2.9% for 2022 (vs. 2.6% for 2021)
  - Consolidated expected long-term return on assets of 6.5% (unchanged from 2021)

Simplified financing structure



(1) Progress Energy HoldCo has long-term debt outstanding, but no future common equity issuance is planned at this financing entity
(2) 11.05% of Duke Energy Indiana Holdco membership interest owned by GIC. Upon the second closing, GIC will own 19.9%

Credit ratings and 2021 credit metrics(1)

Current Ratings	Moody's	S&P
DUKE ENERGY CORPORATION	Stable	Stable
Senior Unsecured Debt	Baa2	BBB
Commercial Paper	P-2	A-2
PROGRESS ENERGY, INC	Stable	Stable
Senior Unsecured Debt	Baa1	BBB
DUKE ENERGY CAROLINAS	Stable	Stable
Senior Secured Debt	Aa3	A
Senior Unsecured Debt	A2	BBB+
DUKE ENERGY PROGRESS	Stable	Stable
Senior Secured Debt	Aa3	A
Senior Unsecured Debt	A2	BBB+
DUKE ENERGY FLORIDA	Stable	Stable
Senior Secured Debt	A1	A
Senior Unsecured Debt	A3	BBB+
DUKE ENERGY INDIANA	Stable	Stable
Senior Secured Debt	Aa3	A
Senior Unsecured Debt	A2	BBB+
DUKE ENERGY OHIO	Stable	Stable
Senior Secured Debt	A2	A
Senior Unsecured Debt	Baa1	BBB+
DUKE ENERGY KENTUCKY	Stable	Stable
Senior Unsecured Debt	Baa1	BBB+
PIEDMONT NATURAL GAS	Stable	Stable
Senior Unsecured Debt	A3	BBB+

	Duke Energy Corporation
Holdco Debt/Total Debt	32%
FFO/Debt (2)(3)	15%

	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida
FFO/Debt(2)(3)	23%	23%	22%

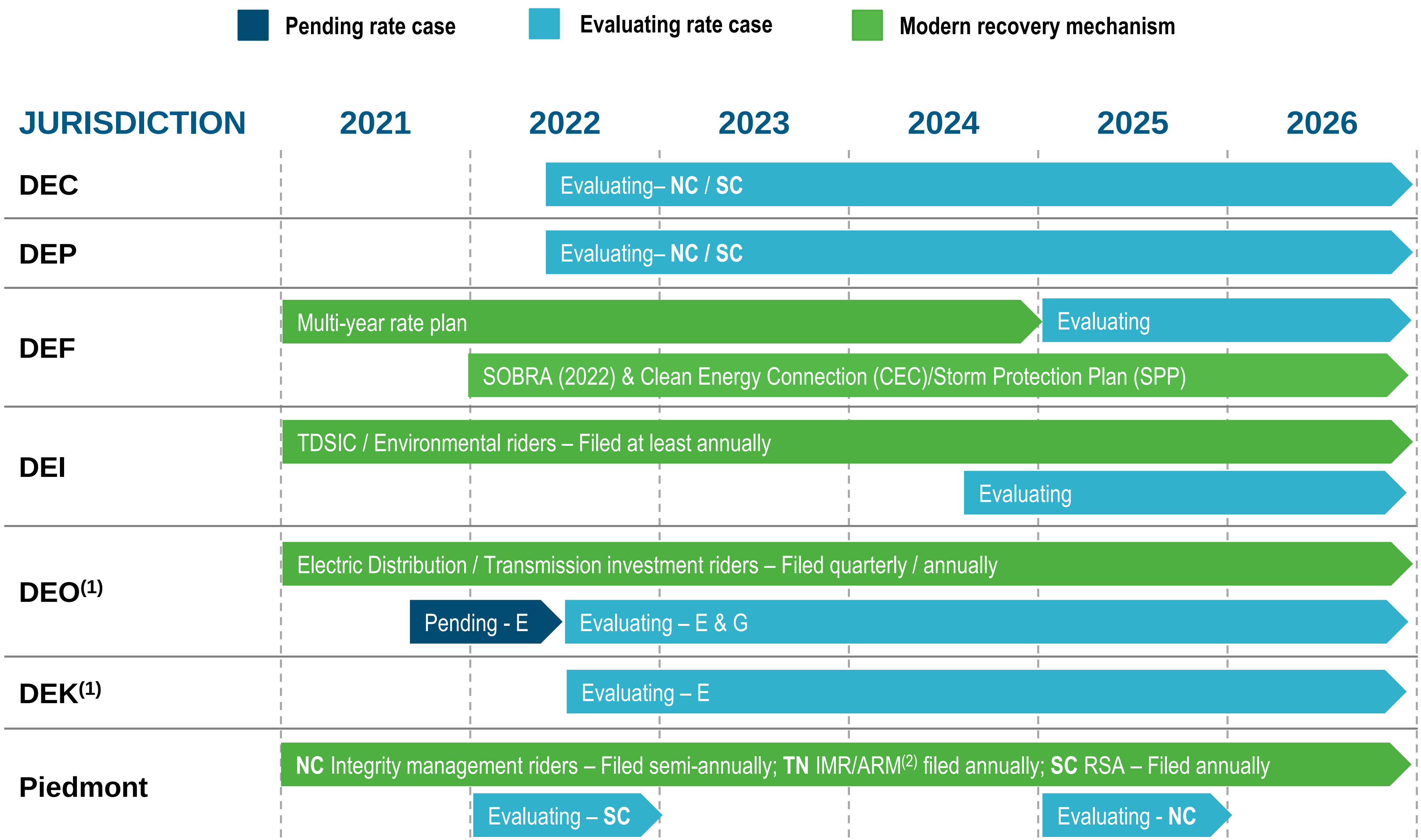
	Duke Energy Indiana	Duke Energy Ohio Cons.	Piedmont
FFO/Debt(2)(3)	25%	16%	15%

Simplified 2022 Cash Flows	
Adjusted net income(4)	$4,195
Depreciation & amortization	5,885
Deferred and accrued taxes	350
Other sources / (uses), net(5)	(1,180)
Primary sources	**9,250**
Capital expenditures	(12,350)
Dividends (subject to Board of Directors discretion)	(3,065)
Primary uses	**(15,415)**
Uses in excess of sources	(6,165)
Net Change in debt	6,030
Net Change in Cash	**($135)**

(1) Amounts do not include all adjustments that may be made by the rating agencies
(2) Key adjustments within the computation include the removal of coal ash remediation spending from FFO, and the adjusted debt balance excludes purchase accounting adjustments
(3) Assumes securitization treated as off credit
(4) Based upon the midpoint of the 2022 guidance range
(5) Includes cost of removal expenditures, changes in working capital and AFUDC equity

REGULATORY OVERVIEW

Regulatory calendar



(1) "E" denotes Electric, "G" denotes Gas
(2) Piedmont's operation under the Annual Review Mechanism (ARM) in lieu of operation under the Integrity Management Rider (IMR) in Tennessee is currently pending TPUC approval.

Overview of state commissions by jurisdiction

	North Carolina	South Carolina	Florida	Indiana	Ohio	Kentucky	Tennessee
Number of Commissioners	7	7	5	5	5	3	7
Term (years)	6	4	4	4	5	4	6
Appointed/Elected	Appointed by Governor	Elected by the General Assembly	Appointed by Governor	Appointed by Governor	Appointed by Governor	Appointed by Governor	Appointed by Governor and Legislature
Chair *(Term Exp.)*	Charlotte Mitchell *(June 2023)*	Justin Williams *(June 2022)*	Andrew Fay *(January 2026)*	Jim Huston *(April 2025)*	Jenifer French *(April 2024)*	Kent Chandler *(June 2024)*	Kenneth Hill *(June 2026)*
Other Commissioners *(Term Exp.)*	▪ Lyons Gray (June 2021) ▪ ToNola Brown-Bland (June 2023) ▪ Dan Clodfelter (June 2023) ▪ Floyd McKissick (June 2025) ▪ Kimberly Duffley (June 2025) ▪ Jeff Hughes (June 2025)	▪ Tom Ervin (June 2022) ▪ Florence Belser (February 2023) ▪ Mike Caston (June 2024) ▪ Headen Thomas (June 2024) ▪ Carolee Williams (June 2024) ▪ Delton Powers (June 2024)	▪ Art Graham (January 2026) ▪ Gary Clark (January 2023) ▪ Mike La Rosa (January 2025) ▪ Gabriella Passidomo (January 2023)	▪ Sarah Freeman (January 2026) ▪ Stefanie Krevda (April 2022) ▪ David Ziegner (April 2023) ▪ David Ober (January 2024)	▪ Lawrence Friedeman (April 2025) ▪ Dennis Deters (April 2026) ▪ Daniel Conway (April 2022) ▪ Beth Trombold (April 2023)	▪ Amy Cubbage-Vice Chair (July 2023) ▪ Marianne Butler (July 2025)	▪ Clay Good (June 2026) ▪ Robin Morrison (June 2026) ▪ Herbert Hilliard (June 2023) ▪ John Hie (June 2024) ▪ David Jones (June 2024) ▪ Vacant (June 2026)

Current electric rate information by jurisdiction

	North Carolina	South[(1)] Carolina	Florida	Indiana	Ohio (Electric)	Kentucky (Electric)
Retail Rate Base	$16.9 B [(2)] (DEC) $10.6 B [(2)] (DEP)	$5.4 B (DEC) $1.5 B (DEP)	$15.6 B [(3)]	$10.2 B	$1.3 B (dist. only)	$881 M
Wholesale Rate Base	$2.2 B (DEC) 3Q 2021 $3.7 B (DEP) 3Q 2021		$1.8 B [(3)]	$579 M	$0.7 B (trans. only)	$0
Allowed ROE	9.6% (DEC & DEP)	9.5% (DEC & DEP)	10.50% / 9.85% [(4)]	9.7%	9.84% - Dist 11.38% - Trans	9.25%
Allowed Equity	52.0% (DEC & DEP)	53.0% (DEC & DEP)	53% [(5)]	41.62% [(6)]	50.8%	48.2%
Effective Date of Most Recent Rates	6/1/21 (DEC & DEP)	6/1/19 (DEC & DEP)	1/1/22	7/30/20 [(7)]	Distr: 1/2/19 Trans 6/1/21 ESP: 1/2/19	5/1/20
Fuel Clause Updated	Annually (DEC & DEP)	Annually (DEC & DEP)	Annually	Quarterly	Annually for Non-Shoppers	Monthly
Environmental Clause Updated	N/A	N/A	Annually	Semi-Annually	Quarterly	Monthly

(1) DEC SC and DEP SC rate base and allowed ROE as of June 2019. The Public Service Commission of South Carolina issued orders in the DEC SC and DEP SC rate cases on May 21, 2019.
(2) DEC NC and DEP NC rate base and allowed ROE as of June 2021. The NCUC issued orders in the DEC NC rate case on March 31, 2021 and in the DEP NC rate case on April 16, 2021.
(3) Florida's thirteen-month average as of November 2021. Retail rate base includes amounts recovered in base rates of $15.1B and amounts recovered in trackers of $0.5B.
(4) Represents the mid-point of an authorized range from 9.5% to 11.5% through December 2021. ROE midpoint changes to 9.85% with a range of 8.85% to 10.85% in January 2022.
(5) Florida's equity ratio is effective January 2022. Florida's regulatory capital structure also includes accumulated deferred income taxes (ADIT), customer deposits and investment tax credits (ITC).
(6) Indiana's capital structure includes ADIT. When ADIT is excluded, the capital structure approximates 54% equity as of December 31, 2020.
(7) Step 2 rates went into effect August 2021, retroactive to 1/1/2021.

Current electric rate information by jurisdiction (continued)

General Rate Case Provisions	North Carolina	South Carolina	Florida	Indiana	Ohio (Electric)	Kentucky (Electric)
Notice of Intent Required?	Yes	Yes	Yes	Yes (1)	Yes	Yes
Notice Period	30 Days	30 Days	60 Days	30 Days (2)	30 Days	30 Days
Base Rate Case Test Year	Historical (3)	Historical (3)	Projected	Optional (4)	Partially Projected	Forecast Optional
Multi-Year Rate Plan	Yes (5)	No	Yes	No	No	No
Time Limitation Between Cases	Only under multi-year rate plan	12 months	No	15 Months	No	No
Rates Effective Subject to Refund	7 Months After Filing	6 Months After Filing (6)	8 Months After Filing	10 Months After Filing (7)	9 Months After Filing	6 Months After Filing (8)

Recovery mechanisms for certain capital investments	North Carolina	South Carolina	Florida	Indiana	Ohio (Electric)	Kentucky (Electric)
Grid Modernization	Deferral / base rate case	Deferral / base rate case	Rider / base rate case	Rider / base rate case	Rider / base rate case	Base rate case
Renewables	Base rate case	Base rate case	Rider / base rate case	Rider / base rate case	N/A	Base rate case
Environmental	Deferral / base rate case	Deferral / base rate case	Rider / base rate case	Rider / base rate case	N/A	Rider / base rate case

(1) *IURC recommended procedure. Not a statutory requirement*
(2) *As least 30 days to avoid ex parte issues*
(3) *Historical, adjusted for known and measurable changes*
(4) *Utilities may elect to a historical test period, a forward-looking test period, or a hybrid test year in the context of a general rate case*
(5) *Performance based regulation includes known and measurable changes for up to 3 years, with annual cap of 4%.*
(6) *If the South Carolina Commission fails to rule on a rate case filing within 6 months, the new rates can be implemented and are not subject to refund. There is a grace period here. The Company would have to notify the Commission that it planned to put rates in and the Commission would then have 10 additional days to issue an order*
(7) *The utility may implement interim rates, subject to refund, if the IURC has not rendered a decision within 10 months of filing (can be extended 60 days by IURC). The interim rates are not to exceed 50% of the original request*
(8) *The effective date is 7 months after filing for a forecasted test year*

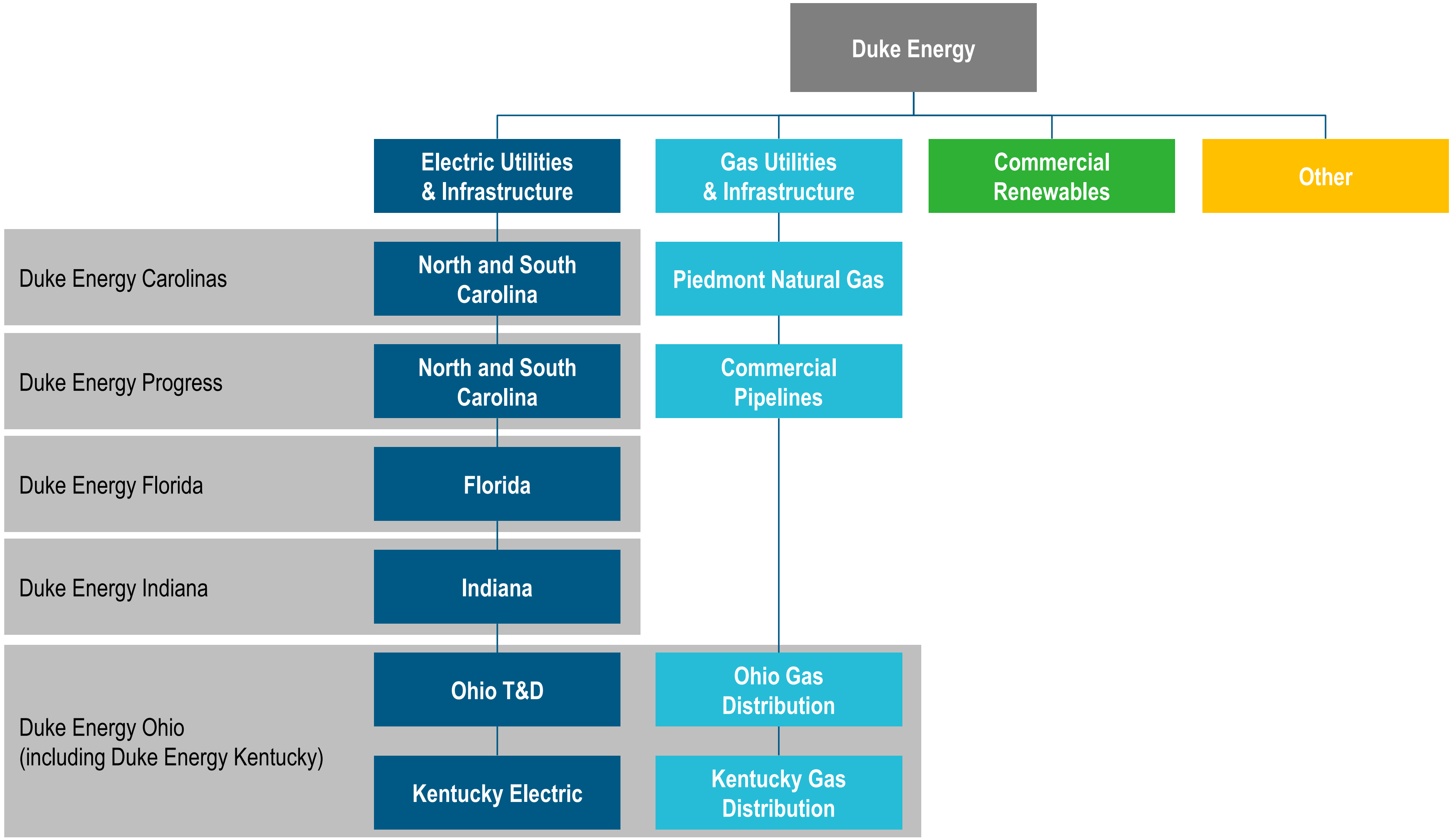
Current gas rate information by jurisdiction

	North Carolina	South Carolina	Tennessee	Ohio (Gas)	Kentucky (Gas)
Rate Base	$4.7 billion	$452 million	$897 million	$900 million	$313 million
Allowed ROE	9.6%	9.8%	9.8%	9.84%	9.375% for base rates 9.3% for riders
Allowed Equity	51.6%	52.2%	50.5%	53.3%	51%
Effective Date of Most Recent Rates	11/1/21	11/1/21(1)	1/2/21	12/1/13	1/4/22
Significant Rider Mechanisms	Margin Decoupling Rider Integrity Management Rider Fuel Clause	Rate Stabilization Adj. Weather Normalization Adj. Fuel Clause	Weather Normalization Adj. Integrity Management Rider(2) Fuel Clause	AMRP Fuel Clause Capital Expenditure	Weather Normalization Adj. Fuel Clause PHMSA-required capital(3)

(1) As updated pursuant to the South Carolina Rate Stabilization Act (RSA)
(2) Piedmont's operation under the Annual Review Mechanism (ARM) in lieu of operation under the Integrity Management Rider (IMR) in Tennessee is currently pending TPUC approval
(3) PHMSA rider has an annual 5% rate increase cap and only applies to AM07 upon CPCN approval.

SEGMENT OVERVIEWS

Duke Energy business segment structure



Duke Energy – a large scale, highly regulated energy infrastructure company

HEADQUARTERED IN CHARLOTTE, NC

DUK
LISTED
NYSE

A FORTUNE 150 COMPANY

$80 B
MARKET CAP
(AS OF 2/8/2021)

$170 B
TOTAL ASSETS
(AS OF 12/31/2021)

28 K
EMPLOYEES
(AS OF 12/31/2021)

54 GWs
TOTAL GENERATING CAPACITY (AS OF 12/31/2021)

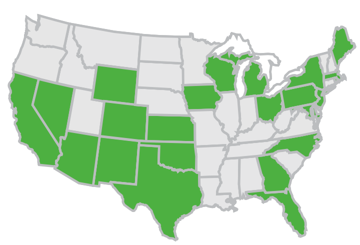
ELECTRIC UTILITIES & INFRASTRUCTURE

- Operating in six constructive jurisdictions, with attractive allowed ROEs, serving 8.2 million retail customers
- Customer rates below the national average(1)
- Balanced generation portfolio that has reduced its carbon emissions by 44% since 2005(2)
- Industry-leading safety performance, as recognized by EEI

GAS UTILITIES & INFRASTRUCTURE

- Five state LDCs serving 1.6 million customers
- Strong earnings trajectory driven by customer growth, system integrity improvements, and continued expansion of natural gas infrastructure
- Efficient recovery mechanisms allow for timely recovery of investments

COMMERCIAL RENEWABLES

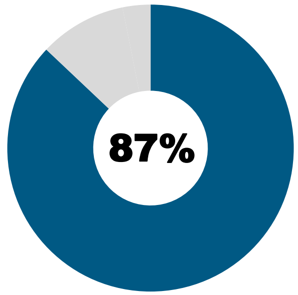


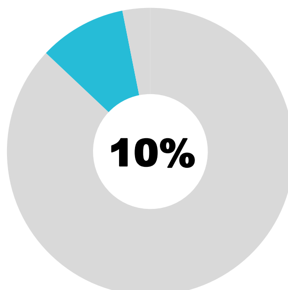
- Approximately 5 GWs of wind and solar in operation
- Long-term Power Purchase Agreements with creditworthy counterparties

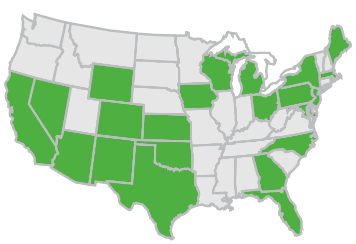
(1) Typical bill rates (¢/kWh) in effect as of January 1, 2021. Vertically integrated utilities only. Source: EEI Typical Bills and Avg. Rates Report, Winter 2021.
(2) Year to year reductions will be influenced by customer demand for electricity, weather, fuel and purchased power costs and other factors.

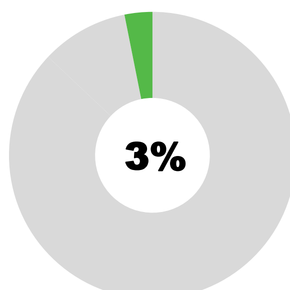
Complementary businesses with strong growth opportunities

	2022 ADJUSTED **EPS CONTRIBUTION**(1)	2022-2026 **CAPEX**
ELECTRIC UTILITIES & INFRASTRUCTURE	87%	$53.2 B
GAS UTILITIES & INFRASTRUCTURE	10%	$5.8 B
COMMERCIAL RENEWABLES	3%	$2.5 B(3)



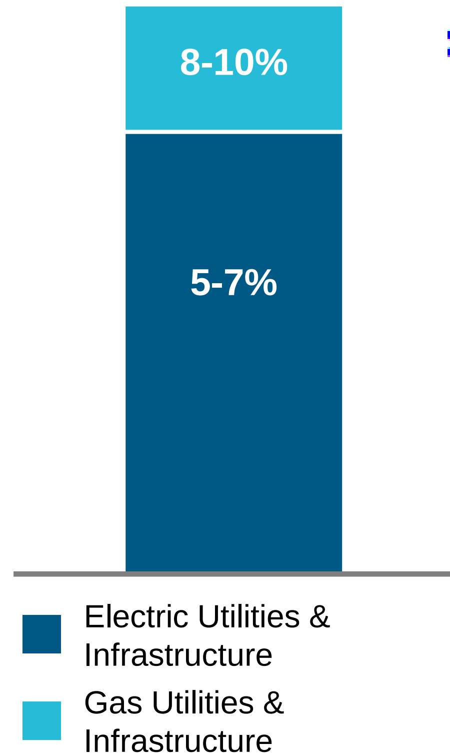






2022 – 2026 ADJUSTED EPS CAGR(2)

Consolidated 5-7%



(1) Based upon the midpoint of the 2022 adjusted EPS guidance range of $5.30-$5.60 per share; excludes the impact of Other

(2) CAGR off of the components of the midpoint of the 2021 EPS guidance range of $5.00-$5.30 per share; consolidated growth rate includes the impact of Commercial Renewables (approximately flat growth) and Other

(3) Net of tax equity financing

Electric utilities & infrastructure

EIGHT UTILITIES IN HIGH-QUALITY REGIONS OF THE U.S.

CAROLINAS

Duke Energy Carolinas (NC/SC)

Duke Energy Progress (NC/SC)

FLORIDA

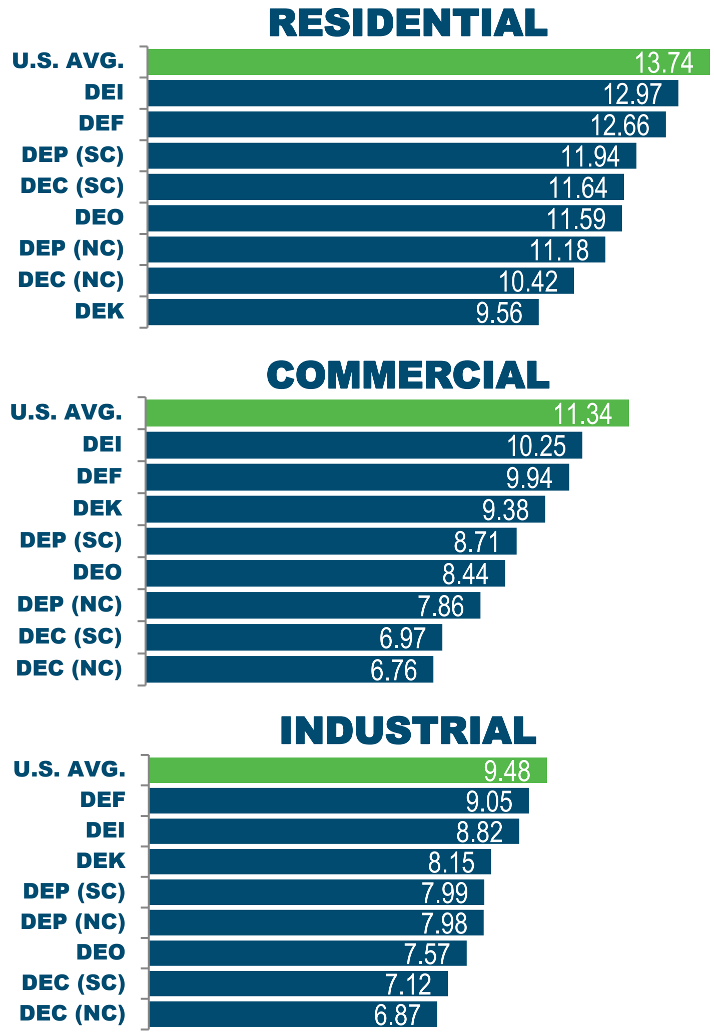
Duke Energy Florida

MIDWEST

Duke Energy Indiana

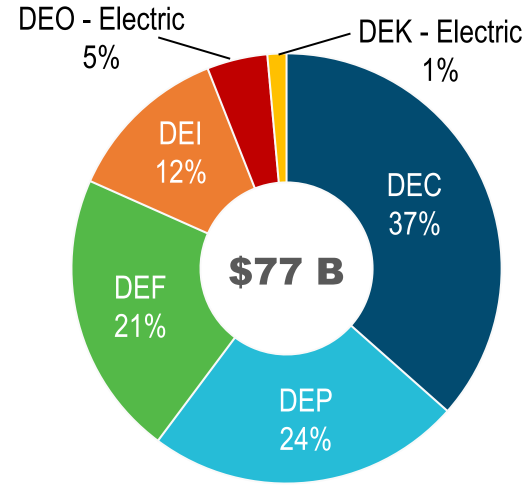
Duke Energy Ohio / Kentucky

COMPETITIVE CUSTOMER RATES(1)

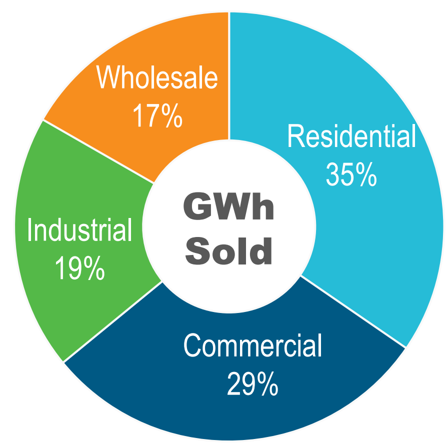


(1) *Typical bill rates (¢/kWh) in effect as of January 1, 2021. Source: EEI Typical Bills and Avg. Rates Report, Winter 2021.*

REGULATED ELECTRIC 2021 EARNINGS BASE



BALANCED CUSTOMER MIX



Duke's scale enables top tier O&M performance

Duke Energy compares favorably against peer group across multiple O&M metrics

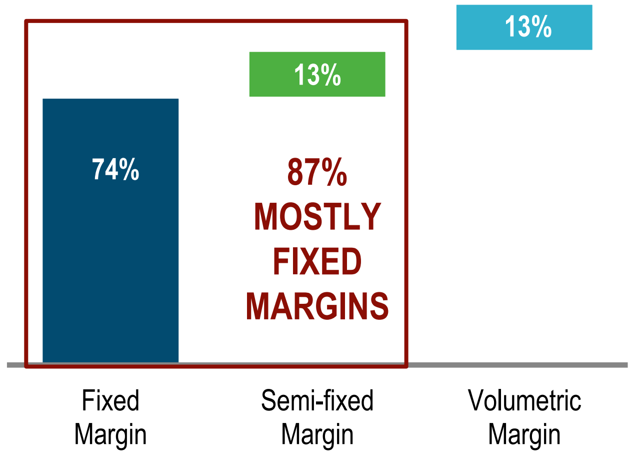
- #2 on non-generation O&M cost per customer vs. peer utilities
  - Peer group: AEP, SO, EXC, NEE, D, XEL, ED, ES, WEC
- Scale better positions Duke to drive O&M efficiencies
- O&M efficiency keeps customer rates low and creates headroom for growth

Key Metrics(1)	Electric non-generation O&M(2) / Customer	Electric non-generation O&M(2) / MWh	Distribution and Transmission O&M / Customer
PEER AVERAGE	$490	$24	$243
DUKE ENERGY	$359	$14	$144
DUKE RANKING (out of 10)	#2	#2	#2

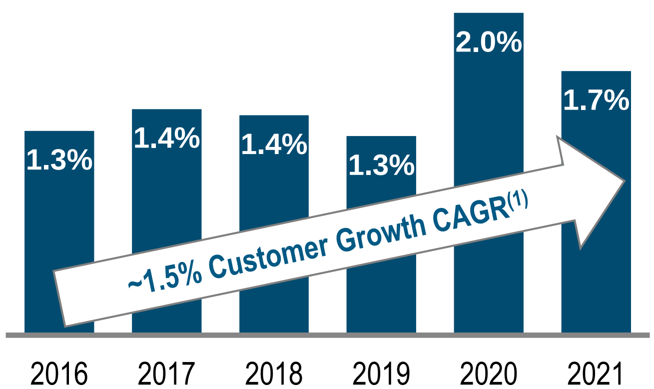
(1) *Source: SNL FERC Form 1, annual filings and investor presentations; data as of YE 2020. Peer group: AEP, SO, EXC, NEE, D, XEL, ED, ES, WEC*
(2) *Reflects total electric O&M net of power production O&M.*

Gas utilities & infrastructure

GAS UTILITIES WITH LOW VOLUMETRIC EXPOSURE DUE TO **MOSTLY FIXED MARGINS…**



…WITH EARNINGS DRIVEN BY **INVESTMENT AND STRONG RESIDENTIAL CUSTOMER GROWTH**



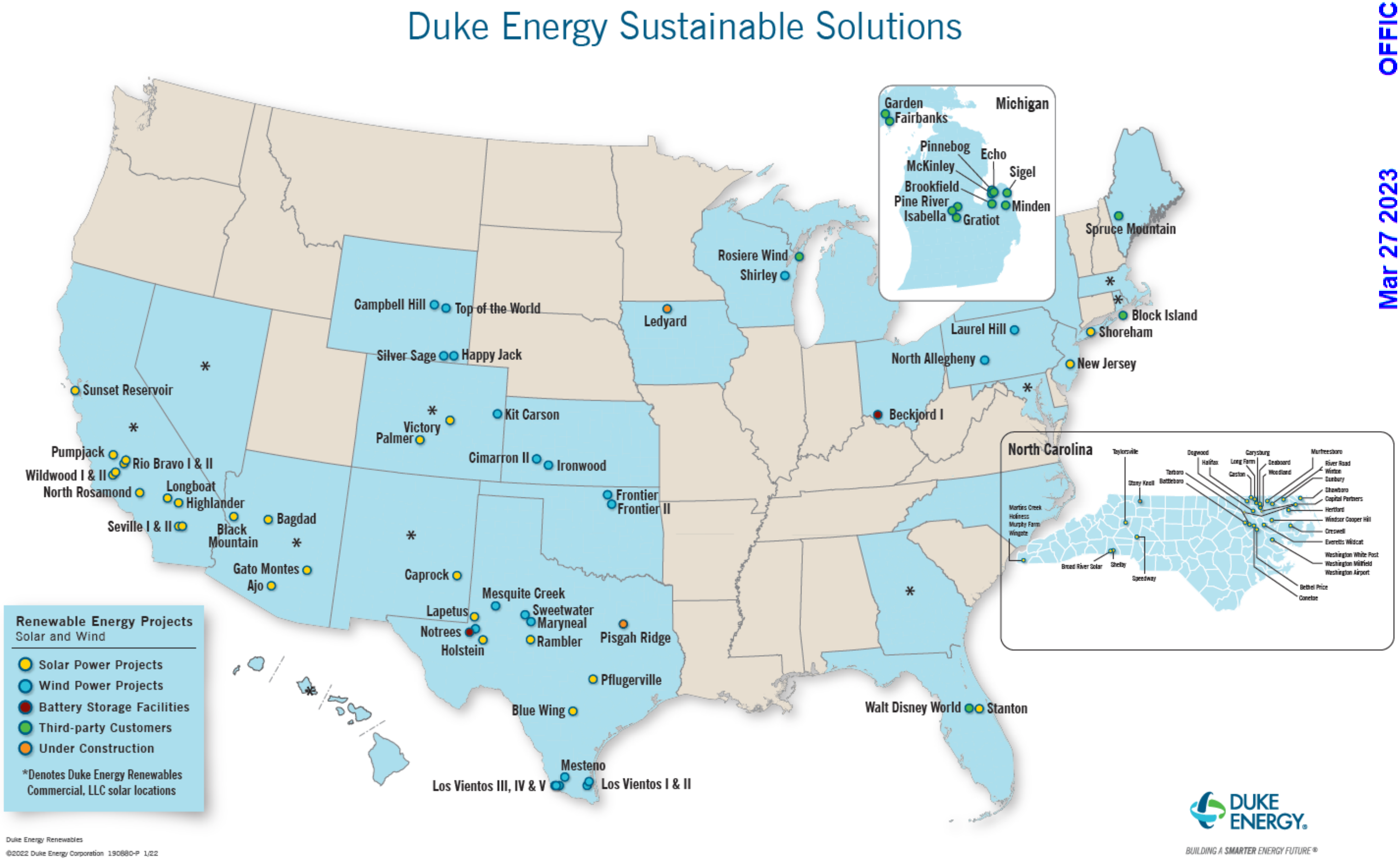
MARGIN STABILIZING MECHANISMS

1. Purchased Gas Adjustment	All States
2. Uncollectible Recovery	All States
3. Integrity Management Rider ("IMR")	North Carolina and Tennessee(2)
4. Margin Decoupling	North Carolina
5. Weather Normalization	South Carolina, Tennessee and Kentucky
6. Rate Stabilization Act	South Carolina
7. Accelerated Main Replacement Program Rider	Ohio
8. Fixed Customer Charge	All States

(1) Piedmont CAGR: 1.9%, Midwest LDC CAGR 0.9%
(2) Piedmont's operation under the Annual Review Mechanism (ARM) in lieu of operation under the Integrity Management Rider (IMR) in Tennessee is currently pending TPUC approval

Commercial Renewables asset locations

A full list of generation facilities can be found at:
https://www.duke-energy.com//_/media/pdfs/our-company/investors/duke-energy-generation-portfolio.pdf



Upcoming events

Event	Date
1Q 2022 earnings call (tentative)	May 9, 2022
2Q 2022 earnings call (tentative)	August 4, 2022
ESG Day	October 4, 2022
3Q 2022 earnings call (tentative)	November 4, 2022

Investor relations contact information

JACK SULLIVAN, VICE PRESIDENT INVESTOR RELATIONS

- Jack.Sullivan@duke-energy.com
- (980) 373-3564

CHRIS JACOBI, DIRECTOR INVESTOR RELATIONS

- Christopher.Jacobi@duke-energy.com
- (704) 382-8397

LINDA MILLER, MANAGER INVESTOR RELATIONS

- Linda.Miller@duke-energy.com
- (980) 373-2407

DUKE ENERGY®

BUILDING A SMARTER ENERGY FUTURE ®

For additional information on Duke Energy,
please visit: duke-energy.com/investors

Duke Energy Corporation
Non-GAAP Reconciliations
Fourth Quarter Earnings Review & Business Update
February 10, 2022

Adjusted Earnings per Share (EPS)

The materials for Duke Energy Corporation's (Duke Energy) Fourth Quarter Earnings Review and Business Update on February 10, 2022, include a discussion of adjusted EPS for the year-to-date periods ended December 31, 2021 and 2020.

The non-GAAP financial measure, adjusted EPS, represents basic EPS available to Duke Energy Corporation common stockholders (GAAP reported EPS), adjusted for the per share impact of special items. As discussed below, special items represent certain charges and credits, which management believes are not indicative of Duke Energy's ongoing performance.

Management believes the presentation of adjusted EPS provides useful information to investors, as it provides them with an additional relevant comparison of Duke Energy's performance across periods. Management uses this non-GAAP financial measure for planning and forecasting and for reporting financial results to the Duke Energy Board of Directors, employees, stockholders, analysts and investors. Adjusted EPS is also used as a basis for employee incentive bonuses. The most directly comparable GAAP measure for adjusted EPS is reported basic EPS available to Duke Energy Corporation common stockholders. Reconciliations of adjusted EPS for the year-to-date periods ended December 31, 2021 and 2020, to the most directly comparable GAAP measure are included herein.

Special items included in the periods presented include the following items, which management believes do not reflect ongoing costs:

- Workplace and Workforce Realignment represents costs attributable to business transformation, including long-term real estate strategy changes and workforce realignment.
- Regulatory Settlements represents an impairment charge related to the South Carolina Supreme Court decision on coal ash, insurance proceeds and Duke Energy Carolinas and Duke Energy Progress coal ash settlement and the partial settlements in the 2019 North Carolina rate cases.
- Gas Pipeline Investments represents costs related to the cancellation of the ACP investment and additional exit obligations.
- Severance represents the reversal of 2018 Severance charges, which were deferred as a result of a partial settlement in the Duke Energy Carolinas and Duke Energy Progress 2019 North Carolina rate cases.

Adjusted EPS Guidance

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 10, 2022, include a reference to revised forecasted 2021 adjusted earnings guidance range of \$5.15 to \$5.30 per share, narrowed from the original forecasted 2021 adjusted earnings guidance range of \$5.00 to \$5.30 per share during the third quarter of 2021. In addition, the materials reference the midpoint of original forecasted 2021 adjusted earnings guidance of approximately \$5.15. The materials also include a reference to the preliminary estimate of 2022 adjusted EPS guidance range of \$5.30 to \$5.60. In addition, the materials reference a preliminary estimate of the 2022 adjusted EPS midpoint of approximately \$5.45. The materials also reference the long-term range of annual growth of 5% - 7% through 2026 off the midpoint of original 2021 adjusted EPS guidance range of \$5.15. In addition, the materials reference the expected five-year adjusted EPS growth in the natural gas segment of 8%-10% and in the electric segment of 5%-7% (on a compound annual growth rate (CAGR) basis). The forecasted adjusted EPS is a non-GAAP financial measure as it represents basic EPS available to Duke Energy Corporation common stockholders (GAAP reported EPS), adjusted for the per share impact of special items (as discussed above under Adjusted EPS).

Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items for future periods, such as legal settlements, the impact of regulatory orders or asset impairments.

Adjusted Segment Income (Loss) and Adjusted Other Net Loss

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 10, 2022, include a discussion of adjusted segment income (loss) and adjusted other net loss for the year-to-date period ended December 31, 2021 and a discussion of 2021 and 2022 forecasted adjusted segment income and forecasted adjusted other net loss.

Adjusted segment income (loss) and adjusted other net loss are non-GAAP financial measures, as they represent reported segment income (loss) and other net loss adjusted for special items (as discussed above under Adjusted EPS). Management believes the presentation of adjusted segment income (loss) and adjusted other net expense provides useful information to investors, as it provides an additional relevant comparison of a segment's or Other's performance across periods. When a per share impact is provided for a segment income (loss) driver, the after-tax driver is derived using the pretax amount of the item less income taxes based on the segment statutory tax rate of 24% for Electric Utilities and Infrastructure, 23% for Gas Utilities and Infrastructure and Other, or an effective tax rate for Commercial Renewables. The after-tax earnings drivers are divided by the Duke Energy weighted average shares outstanding for the period. The most directly comparable GAAP measures for adjusted segment income (loss) and adjusted other net loss are reported segment income (loss) and other net loss, which represents segment income (loss) and other net loss from continuing operations, including any special items. Reconciliations of adjusted segment income (loss) and adjusted other net loss for the year-to-date period ended December 31, 2021, to the most directly comparable GAAP measures is included herein. Due to the forward-looking nature of any forecasted adjusted segment income (loss) and forecasted other net loss and any related growth rates for future periods, information to reconcile these non-GAAP financial measures to the most directly comparable GAAP financial measures are not available at this time, as the company is unable to forecast all special items, as discussed above under Adjusted EPS guidance.

Effective Tax Rate Including Impacts of Noncontrolling Interests and Preferred Dividends and Excluding Special Items

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 10, 2022, include a discussion of the effective tax rate including impacts of noncontrolling interests and preferred dividends and excluding special items for the year-to-date period ended December 31, 2021. The materials also include a discussion of the 2021 and 2022 forecasted effective tax rate including impacts of noncontrolling interests and preferred dividends and excluding special items. Effective tax rate including impacts of noncontrolling interests and preferred dividends and excluding special items is a non-GAAP financial measure as the rate is calculated using pretax income and income tax expense, both adjusted for the impact of special items, noncontrolling interests and preferred dividends. The most directly comparable GAAP measure is reported effective tax rate, which includes the impact of special items and excludes the impacts of noncontrolling interests and preferred dividends. A reconciliation of this non-GAAP financial measure for the year-to-date period ended December 31, 2021, to the most directly comparable GAAP measure is included herein. Due to the forward-looking nature of the forecasted effective tax rates including impacts of noncontrolling interests and preferred dividends and excluding special items, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted EPS Guidance.

Adjusted Book Return on Equity (ROE)

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 10, 2022 include a reference to the historical and projected adjusted book return on equity (ROE) ratio. This ratio is a non-GAAP financial measure. The numerator represents Net Income, adjusted for the impact of special items (as discussed above under Adjusted EPS). The denominator is average Total Common Stockholder's Equity, reduced for Goodwill. A reconciliation of the components of adjusted ROE to the most directly comparable GAAP measures is included here-in. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted EPS Guidance.

Available Liquidity

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 10, 2022, include a discussion of Duke Energy's available liquidity balance. The available liquidity balance presented is a non-GAAP financial measure as it represents cash and cash equivalents, excluding certain amounts held in foreign jurisdictions and cash otherwise unavailable for operations, the remaining availability under Duke Energy's available credit facilities, including the master credit facility as of December 31, 2021. The most directly comparable GAAP financial measure for available liquidity is cash and cash equivalents. A reconciliation of available liquidity as of December 31, 2021, to the most directly comparable GAAP measure is included herein.

Holdco Debt Percentage

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 10, 2022 include a reference to a historical and projected Holdco debt percentage. This percentage reflects a non-GAAP financial measure. The numerator of the Holdco debt percentage is the balance of Duke Energy Corporate debt, Progress Energy, Inc. debt, PremierNotes and the Commercial Paper attributed to the Holding Company. The denominator for the percentage is the balance of long-term debt (excluding purchase accounting adjustments), including current maturities, operating lease liabilities, plus notes payable and commercial paper outstanding.

Funds From Operations ("FFO") Ratio

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 10, 2022 include a reference to the historical and expected FFO to Total Debt ratio. This ratio reflects non-GAAP financial measures. The numerator of the FFO to Total Debt ratio is calculated principally by using net cash provided by operating activities on a GAAP basis, adjusted for changes in working capital, ARO spend, depreciation and amortization of operating leases, operating activities allocated to the Duke Energy Indiana minority interest and reduced for capitalized interest (including any AFUDC interest). The denominator for the FFO to Total Debt ratio is calculated principally by using the balance of long-term debt (excluding purchase accounting adjustments, long-term debt allocated to the Duke Energy Indiana minority interest, and long-term debt associated with the CR3 and Duke Energy Carolinas and Duke Energy Progress Storm Securitizations), including current maturities, operating lease liabilities, plus notes payable, commercial paper outstanding, underfunded pension liability, and adjustments to hybrid debt and preferred stock issuances based on how credit rating agencies view the instruments. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted EPS Guidance.

Net Regulated Electric and Gas O&M

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 10, 2022, include a discussion of Duke Energy's net regulated Electric and Gas operating, maintenance and other expenses (O&M) for the year-to-date periods ended December 31, 2019 and 2016, as well as the forecasted year-to-date period ended December 31, 2022.

Net regulated Electric and Gas O&M is a non-GAAP financial measure, as it represents reported O&M expenses adjusted for special items and expenses recovered through riders and excludes O&M expenses for Duke Energy's non-margin based Commercial businesses and non-regulated electric products and services supporting regulated operations.

The materials also reference Piedmont Natural Gas Company, Inc. (Piedmont) Net regulated Gas O&M for the year ended December 31, 2016. Piedmont O&M is a non-GAAP finance measure, as it represents reported O&M expense as of December 31, 2016, adjusted for special items.

Management believes the presentation of net regulated Electric and Gas O&M and Piedmont Net regulated Gas O&M provides useful information to investors, as it provides a meaningful comparison of financial performance across periods. The most directly comparable GAAP financial measure for net regulated Electric and Gas O&M and Piedmont Net regulated Gas O&M is reported operating, maintenance and other expenses. A reconciliation of net regulated Electric and Gas O&M for the year-to-date periods ended December 31, 2019 and 2016, as well as the forecasted year-to-date period ended December 31, 2022, and a reconciliation of Piedmont O&M for the year-to-date period ended October 31, 2016, to the most directly comparable GAAP measure are included here-in.

Business Mix Percentage

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 10, 2022, reference ninety-five percent of earnings coming from regulated electric and gas utilities, eighty-six percent from regulated electric and nine percent from regulated gas, and five percent coming from commercial renewables, as a percentage of total 2021 adjusted segment income (i.e. earnings contribution). The materials also reference each segment's 2022 projected adjusted segment income as a percentage of the total projected 2022 adjusted EPS midpoint of approximately $5.45 (i.e. business mix), excluding the impact of Other. Duke

Energy's segments are comprised of Electric Utilities and Infrastructure, Gas Utilities and Infrastructure and Commercial Renewables.

Adjusted segment income is a non-GAAP financial measure, as it represents reported segment income adjusted for special items as discussed above. Due to the forward-looking nature of any forecasted adjusted segment income, information to reconcile this non-GAAP financial measure to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items (as discussed above under Adjusted EPS Guidance).

Dividend Payout Ratio

The materials for Duke Energy's Fourth Quarter Earnings Review and Business Update on February 10, 2022, include a discussion of Duke Energy's long-term target dividend payout ratio of 65% - 75% based upon adjusted EPS. This payout ratio is a non-GAAP financial measure as it is based upon forecasted basic EPS from continuing operations available to Duke Energy Corporation stockholders, adjusted for the per-share impact of special items, as discussed above under Adjusted EPS. The most directly comparable GAAP measure for adjusted EPS is reported basic EPS available to Duke Energy Corporation common stockholders. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items, as discussed above under Adjusted EPS Guidance.

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Year Ended December 31, 2021
(Dollars in millions, except per share amounts)

	Reported Earnings	Special Items: Gas Pipeline Investments	Special Items: Workplace and Workforce Realignment	Special Items: Regulatory Settlements	Discontinued Operations	Total Adjustments	Adjusted Earnings
SEGMENT INCOME (LOSS)							
Electric Utilities and Infrastructure	**$ 3,850**	$ —	$ —	$ 69 **C**	$ —	$ 69	$ 3,919
Gas Utilities and Infrastructure	**396**	15 **A**	—	—	—	15	411
Commercial Renewables	**201**	—	—	—	—	—	201
Total Reportable Segment Income	**4,447**	**15**	**—**	**69**	**—**	**84**	**4,531**
Other	**(652)**	—	148 **B**		—	148	(504)
Discontinued Operations	**7**	—	—	—	(7) **D**	(7)	—
Net Income Available to Duke Energy Corporation Common Stockholders	**$ 3,802**	**$ 15**	**$ 148**	**$ 69**	**$ (7)**	**$ 225**	**$ 4,027**
EPS AVAILABLE TO DUKE ENERGY CORPORATION COMMON STOCKHOLDERS	**$ 4.94**	**$ 0.02**	**$ 0.20**	**$ 0.09**	**$ (0.01)**	**$ 0.30**	**$ 5.24**

A - Net of $5 million tax benefit. $20 million recorded within Equity in earnings (losses) of unconsolidated affiliates related to exit obligations for ACP on the Consolidated Statements of Operations.

B - Net of $44 million tax benefit. $133 million recorded within Impairment of assets and other charges, $42 million within Operations, maintenance and other, and $17 million within Depreciation and amortization related to costs attributable to business transformation, including long-term real estate strategy changes and workforce realignment on the Consolidated Statements of Operations.

C - Net of $20 million tax benefit at Duke Energy Carolinas and $1 million tax benefit at Duke Energy Progress.

- $160 million of expense recorded within Impairment of assets and other charges, $77 million of income within Other income and expenses, $5 million of expense within Operations, maintenance and other, $13 million of income within Regulated electric operating revenues, $3 million of expense within Interest expense and $6 million of expense within Depreciation and amortization on the Duke Energy Carolinas' Consolidated Statement of Operations related to the South Carolina Supreme Court decision on coal ash and insurance proceeds.

- $42 million of expense recorded within Impairment of assets and other charges, $34 million of income within Other income and expenses, $7 million of expense within Operations, maintenance and other, $15 million of income within Regulated electric operating revenues, $5 million of expense within Interest expense and $1 million of expense within Depreciation and amortization on the Duke Energy Progress' Consolidated Statement of Operations related to the South Carolina Supreme Court decision on coal ash and insurance proceeds.

D - Recorded in Income (Loss) from Discontinued Operations, net of tax on the Consolidated Statements of Operations.

Weighted Average Shares (reported and adjusted) – 769 million

DUKE ENERGY CORPORATION
REPORTED TO ADJUSTED EARNINGS RECONCILIATION
Year Ended December 31, 2020
(Dollars in millions, except per share amounts)

		Special Items					
	Reported Earnings	Gas Pipeline Investments	Severance	Regulatory Settlements	Discontinued Operations	Total Adjustments	Adjusted Earnings
SEGMENT INCOME (LOSS)							
Electric Utilities and Infrastructure	**$ 2,669**	$ 4 **A**	$ —	$ 872 **D**	$ —	$ 876	$ 3,545
Gas Utilities and Infrastructure	**(1,266)**	1,707 **B**	—	—	—	1,707	441
Commercial Renewables	**286**	—	—	—	—	—	286
Total Reportable Segment Income	**1,689**	**1,711**	**—**	**872**	**—**	**2,583**	**4,272**
Other	**(426)**	$ —	(75) **C**	—	—	(75)	(501)
Discontinued Operations	**7**	—	—	—	(7) **E**	(7)	—
Net Income Available to Duke Energy Corporation Common Stockholders	**$ 1,270**	**$ 1,711**	**$ (75)**	**$ 872**	**$ (7)**	**$ 2,501**	**$ 3,771**
EPS AVAILABLE TO DUKE ENERGY CORPORATION COMMON STOCKHOLDERS	**$ 1.72**	**$ 2.32**	**$ (0.10)**	**$ 1.19**	**$ (0.01)**	**$ 3.40**	**$ 5.12**

.

A - Net of $1 million tax benefit. $5 million included within Impairment charges related to gas pipeline interconnections on the Duke Energy Progress' Consolidated Statements of Operations.

B - Net of $398 million tax benefit.

- $2,098 million recorded within Equity in earnings (losses) of unconsolidated affiliates related to exit obligations for gas pipeline investments on the Consolidated Statements of Operations.
- $7 million included within Impairment charges related to gas project materials on the Piedmont Consolidated Statements of Operations.

C - Net of $23 million tax expense. $98 million reversal of 2018 severance charges recorded within Operations, maintenance and other on the Consolidated Statements of Operations.

D - Net of $123 million tax benefit at Duke Energy Carolinas and $140 million tax benefit at Duke Energy Progress.

- $454 million included within Impairment charges and reversal of $50 million included in Regulated electric operating revenues related to the coal ash settlement filed with the NCUC on the Duke Energy Carolinas' Consolidated Statements of Operations.
- $19 million included within Impairment charges related to the Clemson University Combined Heat and Power Plant and $8 million of shareholder contributions within Operations, maintenance and other on the Duke Energy Carolinas' Consolidated Statements of Operations.
- $494 million included within Impairment charges and reversal of $102 million included in Regulated electric operating revenues related to the coal ash settlement filed with NCUC on the Duke Energy Progress' Consolidated Statements of Operations.
- $8 million of shareholder contributions included within Operations, maintenance and other on the Duke Energy Progress' Consolidated Statements of Operations.

E - Recorded in Income (Loss) from Discontinued Operations, net of tax on the Consolidated Statements of Operations.

Weighted Average Shares (reported and adjusted) – 737 million

DUKE ENERGY CORPORATION
EFFECTIVE TAX RECONCILIATION
December 2021
(Dollars in millions)

	Three Months Ended December 31, 2021		Year Ended December 31, 2021	
	Balance	Effective Tax Rate	Balance	Effective Tax Rate
Reported Income Before Income Taxes From Continuing Operations Before Income Taxes	$ 639		$ 3,764	
Gas Pipeline Investments	—		20	
Workplace and Workforce Realignment	8		192	
Regulatory Settlements	7		90	
Noncontrolling Interests	79		326	
Preferred Dividends	(14)		(106)	
Pretax Income Including Noncontrolling Interests and Preferred Dividends and Excluding Special Items	$ 719		$ 4,286	
Reported Income Tax (Benefit) Expense From Continuing Operations	$ (18)	(2.8)%	$ 192	5.1 %
Gas Pipeline Investments	—		5	
Workplace and Workforce Realignment	2		44	
Regulatory Settlements	2		21	
Noncontrolling interest portion of income taxes[a]	(3)		(3)	
Tax Expense Including Noncontrolling Interests and Preferred Dividends and Excluding Special Items	$ (17)	(2.4%)	$ 259	6.0 %

(a) Income tax related to non-pass through entities for tax purposes.

	Three Months Ended December 31, 2020		Year Ended December 31, 2020	
	Balance	Effective Tax Rate	Balance	Effective Tax Rate
Reported (Loss) Income From Continuing Operations Before Income Taxes	$ (319)		$ 839	
Regulatory Settlements	1,100		1,135	
Gas Pipeline Investments	20		2,110	
Severance	—		(98)	
Noncontrolling Interests	87		295	
Preferred Dividends	(14)		(107)	
Pretax Income Including Noncontrolling Interests and Preferred Dividends and Excluding Special Items	$ 874		$ 4,174	
Reported Income Tax Benefit From Continuing Operations	$ (162)	50.8 %	$ (236)	(28.1)%
Regulatory Settlements	255		263	
Gas Pipeline Investments	4		399	
Severance	—		(23)	
Tax Expense Including Noncontrolling Interests and Preferred Dividends and Excluding Special Items	$ 97	11.1%	$ 403	9.7 %

Duke Energy Corporation
Available Liquidity Reconciliation
As of December 31, 2021
(In millions)

Cash and Cash Equivalents	$ 343	
Less: Certain Amounts Held in Foreign Jurisdictions	(29)	
Less: Unavailable Domestic Cash	(43)	
	271	
Plus: Remaining Availability under Master Credit Facilities and other facilities	5,518	
Total Available Liquidity (a), December 31, 2021	$ 5,789	approximately 5.8 billion

(a) The available liquidity balance presented is a non-GAAP financial measure as it represents Cash and cash equivalents, excluding certain amounts held in foreign jurisdictions and cash otherwise unavailable for operations, and remaining availability under Duke Energy's available credit facilities, including the master credit facility, as of December 31, 2021. The most directly comparable GAAP financial measure for available liquidity is Cash and cash equivalents.

Duke Energy Corporation
Operations, Maintenance and Other Expense
(In millions)

	Actual December 31, 2016	Actual December 31, 2019	Forecast December 31, 2022
Operation, maintenance and other[(a)]	**$6,223**	**$6,066**	**$6,025**
Adjustments:			
Costs to Achieve, Mergers[(b)]	(238)	–	–
Severance[(b)]	(92)	–	–
Reagents Recoverable[(d) (j)]	(93)	(95)	(95)
Energy Efficiency Recoverable[(c)]	(417)	(415)	(409)
Other Deferrals[(e)] and Recoverable[(d) (h) (i)]	(95)	(321)	(233)
Margin based O&M for Commercial Businesses	(185)	(95)	(159)
Short-term incentive payments (over)/under budget	(90)	(112)	–
Non-margin based O&M for Commercial Business[(f)]	(166)	(203)	(319)
Non-regulated Products and Services[(g)]	(83)	(175)	(219)
Net Regulated Electric and Gas, operation, maintenance and other	**$ 4,764**	**$ 4,651**	**$ 4,589**
Piedmont O&M, for the period from October 3, 2016 through December 31, 2016	**(69)**		
Net Regulated Electric and Gas, operation, maintenance and other, excluding Piedmont[(k)]	**$ 4,695**		

(a) As reported in the Consolidated Statements of Operations.

(b) Presented as a special item for the purpose of calculating adjusted earnings and adjusted diluted earnings per share.

(c) Primarily represents expenses to be deferred or recovered through rate riders.

(d) The Duke Energy Indiana Rate Case was effective in mid-year 2020. This Rate Case permitted recovery within base rates of certain costs that had previously been recovered through riders. Accordingly, all prior periods have been recast as if these costs were always included within base rates.

(e) Prior periods have been recast to reflect a change in methodology to present certain deferrals which will be recovered through future rate cases as if they were included in base rates.

(f) Primarily represents expenses from the Commercial Renewables segment.

(g) Primarily represents non-regulated products and services expenses in support of regulated electric and gas utilities.

(h) Florida Vegetation Management has been reclassified to recoverable in the rate case effective in 2022. Accordingly, all prior periods have been recast for comparability.

(i) The Duke Energy Florida Rate Case effective 2022 permits within base rates the recovery of environmental costs (ECRC) which were previously recovered in riders. Accordingly, all prior periods have been recast for comparability.

(j) Duke Energy Indiana Reagents have been reclassified to Recoverable effective in 2022. Accordingly, all prior periods have been recast for comparability.

(k) Net regulated electric and gas, operating maintenance and other, excluding Piedmont presents Net regulated electic and gas O&M for the year ended December 31, 2016, without the operations of Piedmont Natural Gas, which was acquired on October 3, 2016.

Piedmont Natural Gas Company, Inc.
Operations, Maintenance and Other Expense
(In millions)

		Actual
Operation, maintenance and other[(a)] - Piedmont Natural Gas Company, Inc. 10-K	$	**353**
Less:		
Operation, maintenance and other[(b)] - Piedmont Natural Gas Company, Inc. 2015 November and December Activity		53
Add:		
Operation, maintenance and other[(b)] - Piedmont Natural Gas Company, Inc. 2016 November and December Activity		52
Operation, maintenance and other - Piedmont Natural Gas Company, Inc. for the year ending December 31, 2016	**$**	**352**
Adjustments:		
Costs to Achieve, Mergers[(c)]		(63)
Piedmont, Net Regulated Gas O&M for the year enging December 31, 2016	**$**	**289**

(a) As reported in the 2016 Form 10-K Piedmont Natural Gas Condensed Consolidated Statements of Operations and Comprehensive Income as of October 31, 2016.
(b) As reported in the 2016 Form 10-QT Piedmont Natural Gas Condensed Consolidated Statements of Operations and Comprehensive
(c) Primarily represents expenses for acquisition consummation costs, integration, and other related costs in connection with Duke Energy Corporation's acquisition October 3, 2016.

DUKE ENERGY CORPORATION
ADJUSTED BOOK RETURN ON EQUITY (ROEs)
For the period ended December 31, 2021
dollars in millions

	Duke Energy Carolinas	Duke Energy Progress	Total Carolinas	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio Reportable Segments	Piedmont
Reported Net Income 2021	$ 1,336	$ 991	$ 2,327	$ 738	$ 481	$ 219 (2)	$ 303 (3)
Special Items (1)	130	31	161	22	11	-	10
Adjusted Net Income 2021	1,466	1,022	2,488	760	492	219	313
2021							
Equity	13,891	9,551	23,442	8,295	5,015	4,464	3,277 (4)
Goodwill	-	-	-	-	-	920	49
Equity less Goodwill	13,891	9,551	23,442	8,295	5,015	3,544	3,228
2020							
Equity	13,154	9,260	22,414	7,558	4,783	3,935	2,647 (4)
Goodwill	-	-	-	-	-	920	49
Equity less Goodwill	13,154	9,260	22,414	7,558	4,783	3,015	2,598
Average Equity less Goodwill			22,928	7,927	4,899	3,280	2,913
Adjusted Book ROEs			10.9%	9.6%	10.0%	6.7%	10.7%

(1) Impacts of Regulatory Settlements for coal ash, net of tax and Workplace and Workforce Realignment, net of tax

(2) Net Income for 2021 equals Duke Energy Ohio reportable segments segment income

(3) Piedmont Natural Gas Net Income excludes **$7 million** of income related to Investments in Gas Transmission Infrastructure.

2021
310
(7)
303

(4) Reconciliation of Piedmont Natural Gas Equity to reported equity:

	2021	2020
Reported Equity for Piedmont Natural Gas	3,349	2,715
Less: Investments in Gas Transmission Infrastructure	72	68
Piedmont Natural Gas Adjusted Equity	3,277	2,647

DUKE ENERGY CORPORATION
ADJUSTED BOOK RETURN ON EQUITY (ROEs)
For the period ended December 31, 2020
dollars in millions

	Duke Energy Carolinas	Duke Energy Progress	Total Carolinas	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio Reportable Segments		Piedmont	
Reported Net Income 2020	$ 956	$ 415	$ 1,371	$ 771	$ 408	$ 258	(2)	$ 264	(3)
Special Items (1)	358	443	801	-	-	-		7	
Adjusted Net Income 2020	1,314	858	2,172	771	408	258		271	
2020									
Equity	13,154	9,260	22,414	7,558	4,783	3,935		2,647	(4)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	13,154	9,260	22,414	7,558	4,783	3,015		2,598	
2019									
Equity	12,811	9,246	22,057	6,788	4,575	3,687		2,381	(4)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	12,811	9,246	22,057	6,788	4,575	2,767		2,332	
Average Equity less Goodwill			22,236	7,173	4,679	2,891		2,465	
Adjusted Book ROEs			9.8%	10.7%	8.7%	8.9%		11.0%	

(1) Impacts of Regulatory settlement for coal ash, net of tax; Impairment charges for interconnection with ACP, net of tax; Impairment charges and shareholder contributions related to Clemson CHP, net of tax; Severance, net of tax

(2) Net Income for 2020 equals Duke Energy Ohio reportable segments segment income

(3) Piedmont Natural Gas Net Income excludes **$9 million** of income related to Investments in Gas Transmission Infrastructure.

2020
273
(9)
264

(4) Reconciliation of Piedmont Natural Gas Equity to reported equity:

	2020	2019
Reported Equity for Piedmont Natural Gas	2,715	2,443
Less: Investments in Gas Transmission Infrastructure	68	62
Piedmont Natural Gas Adjusted Equity	2,647	2,381

DUKE ENERGY CORPORATION
ADJUSTED BOOK RETURN ON EQUITY (ROEs)
For the period ended December 31, 2019
dollars in millions

	Duke Energy Carolinas	Duke Energy Progress	Total Carolinas	Duke Energy Florida	Duke Energy Indiana	Duke Energy Ohio Reportable Segments		Piedmont	
Reported Net Income 2019	$ 1,403	$ 805	$ 2,208	$ 693	$ 436	$ 244	(2)	$ 196	(4)
Special Items (1)	-	-	-	(27)	-	-		-	
Adjusted Net Income 2019	1,403	805	2,208	666	436	244		196	
2019									
Equity	12,811	9,246	22,057	6,788	4,575	3,687	(3)	2,381	(5)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	12,811	9,246	22,057	6,788	4,575	2,767		2,332	
2018									
Equity	11,683	8,441	20,124	6,095	4,339	3,449	(3)	2,047	(5)
Goodwill	-	-	-	-	-	920		49	
Equity less Goodwill	11,683	8,441	20,124	6,095	4,339	2,529		1,998	
Average Equity less Goodwill			21,091	6,442	4,457	2,648		2,165	
Adjusted Book ROEs			10.5%	10.3%	9.8%	9.2%		9.1%	

(1) Impacts of Citrus County CC, Net of Tax

(2) Net Income for 2019 equals Duke Energy Ohio reportable segments segment income

(3) Reconciliation of Duke Energy Ohio Equity to Equity of the reportable segments:

	2019	2018
Reported Equity for Duke Energy Ohio	3,683	3,445
Less: Non-Reg & Other	(4)	(4)
Duke Energy Ohio Reportable Segments Equity	3,687	3,449

(4) Piedmont Natural Gas Net Income excludes **$6 million** of income related to Investments in Gas Transmission Infrastructure.

	2019
	202
	(6)
	196

(5) Reconciliation of Piedmont Natural Gas Equity to reported equity:

	2019	2018
Reported Equity for Piedmont Natural Gas	2,443	2,091
Less: Investments in Gas Transmission Infrastructure	62	44
Piedmont Natural Gas Adjusted Equity	2,381	2,047

Duke Energy Corporation
2022 Forecasted Cash Flow Reconciliation, Required by SEC Regulation G
February 10, 2022
($ in millions)

		Forecast 2022
Primary Sources:		
Adjusted net income (1)	(a)	$4,195
Depreciation & amortization	(a)	5,885
Deferred and accrued taxes	(a)	350
Other sources / (uses), net	(a)	(1,180)
Total Sources		9,250
Primary Uses:		
Capital expenditures (including discretionary)	(b)	(12,350)
Dividends	(c)	(3,065)
Total Uses		(15,415)
Uses in Excess of Sources		(6,165)
Net Change in Financing		
Debt issuances	(c, d)	9,650
Debt maturities	(c)	(3,620)
Net Change in Debt		6,030
Net Change in Cash		($135)
Reconciliations to forecasted U.S. GAAP reporting amounts:		
Operating cash flow components, sum of (a) from above		$9,250
Reconciling items to GAAP cash flows from operating activities	(2)	465
Net cash provided by operating activities per GAAP Consolidated Statement of Cash Flows		$9,715
Investing cash flow components, (b) from above		($12,350)
Reconciling items to GAAP cash flows from investing activities	(2)	(1,110)
Net cash used in investing activities per GAAP Consolidated Statement of Cash Flows		($13,460)
Financing cash flow components, sum of (c) from above		$2,965
Reconciling items to GAAP cash flows from financing activities	(2)	645
Net cash provided by financing activities per GAAP Consolidated Statement of Cash Flows		$3,610
Debt issuances [(d) from above] includes "Notes payable and commercial paper" which is separately presented per GAAP Consolidated Statements of Cash Flows		
Net decrease in cash and cash equivalents per forecasted GAAP Consolidated Statements of Cash Flows		($135)

Notes:

(1) The forecasted adjusted net income of $4,195 million for 2022 is an illustrative amount based on the midpoint of Duke Energy's adjusted basic EPS outlook range of $5.30-$5.60 per share. Adjusted basic EPS is a non-GAAP financial measure as it represents basic EPS from continuing operations attributable to Duke Energy Corporation shareholders and adjusted for the per-share impact of special items. Special items represent certain charges and credits which management believes will not be recurring on a regular basis, although it is reasonably possible such charges and credits could recur. The most directly comparable GAAP measure for adjusted basic EPS is reported basic EPS from continuing operations attributable to Duke Energy Corporation common shareholders, which includes the impact of special items. Due to the forward-looking nature of this non-GAAP financial measure for future periods, information to reconcile it to the most directly comparable GAAP financial measure is not available at this time, as management is unable to project all special items.

(2) Amount consists primarily of an adjustment for operating cashflow items (principally payments for asset retirement obligations and payment for an accrued liability) included in the "Capital expenditures (including discretionary)" and; an adjustment for investing cash flow items (principally cost of removal expenditures, proceeds from sales of equity investments and other assets, and proceeds from sales and maturities of available-for-sale securities and Other) included in the "Other sources/(uses), net", which are combined for the GAAP reconciliation in Operating activities, and; an adjustment for financing cash flow items (principally proceeds from Noncontrolling Interests initial investments, payments for interest on preferred debt/equity content securities, and Other) included in the "Other sources/(uses), net" and "Capital expenditures (including discretionary)', which are combined for the GAAP reconciliation in Operating activities and Investing activities.

FFO to Debt Calculation
Duke Energy Corporation
(in millions)

	Year Ended December 31, 2021 Actual
Cash From Operations	8,290
Adjust for Working Capital (1)	947
Coal ash ARO spend	439
Include Capitalized Interest as cost	(72)
Hybrid interest adjustment	10
Preferred stock adjustment	(53)
CR3 securitization adjustment	(56)
Storm securitization	(4)
Duke Energy Indiana minority interest adjustment	(43)
Lease-imputed FFO adjustment (D&A)	206
Funds From Operations	**9,664**
Notes payable and commercial paper	3,304
Current maturities of LT debt	3,387
LT debt	60,448
Less: Purchase Accounting adjustments	(1,506)
CR3 securitization	(1,002)
Storm securitization	(995)
Duke Energy Indiana minority interest adjustment	(518)
Underfunded Pension	343
Hybrid debt adjustment	(250)
Preferred stock adjustment	1,000
Operating lease liabilities	1,261
Total Balance Sheet Debt (Including ST)	**65,472**
(1) Working capital detail, excluding MTM	
Receivables	(297)
Inventory	(34)
Other current assets	(1,136)
Accounts payable	249
Taxes accrued	284
Other current liabilities	(13)
	(947)
FFO / Debt	**15%**

FFO to Debt Calculation
Duke Energy Carolinas
(in millions)

	Year Ended December 31, 2021 Actual
Cash From Operations	2,704
Adjust for Working Capital (1)	233
ARO spend	182
Include Capitalized Interest as cost	(29)
Storm securitization	(1)
Lease-imputed FFO adjustment (D&A)	40
Funds From Operations	**3,129**
Current maturities of LT debt	362
LT debt	12,595
LT debt payable to affiliates	318
Notes payable to affiliated companies	226
Storm securitization	(233)
Underfunded Pension	12
Operating lease liabilities	100
Total Balance Sheet Debt (Including ST)	**13,380**
(1) Working capital detail, excluding MTM	
Receivables	(99)
Receivables from affiliates	(66)
Inventory	(16)
Other current assets	(309)
Accounts payable	5
Accounts payable to affiliates	85
Taxes accrued	206
Other current liabilities	(39)
	(233)
FFO / Debt	**23%**

FFO to Debt Calculation
Duke Energy Progress
(in millions)

	Year Ended December 31, 2021 Actual
Cash From Operations	1,956
Adjust for Working Capital (1)	76
Coal ash ARO spend	187
Include Capitalized Interest as cost	(14)
Storm securitization	(3)
Lease-imputed FFO adjustment (D&A)	73
Funds From Operations	**2,275**
Notes payable to affiliated companies	172
Current maturities of LT debt	556
LT debt	9,543
LT debt payable to affiliates	150
Storm securitization	(762)
Underfunded Pension	31
Operating lease liabilities	400
Total Balance Sheet Debt (Including ST)	**10,090**
(1) Working capital detail, excluding MTM	
Receivables	(52)
Receivables from affiliates	(33)
Inventory	(11)
Other current assets	(147)
Accounts payable	12
Accounts payable to affiliates	95
Taxes accrued	83
Other current liabilities	(23)
	(76)
FFO / Debt	**23%**

FFO to Debt Calculation
Duke Energy Florida
(in millions)

	Year Ended December 31, 2021 Actual
Cash From Operations	1,402
Adjust for Working Capital (1)	390
Include Capitalized Interest as cost	(6)
Adjust for CR3	(56)
Lease-imputed FFO adjustment (D&A)	62
Funds From Operations	**1,792**
Notes payable to affiliated companies	199
Current maturities of LT debt	76
LT debt	8,406
Adjust for CR3	(1,002)
Underfunded Pension	42
Operating lease liabilities	300
Total Balance Sheet Debt (Including ST)	**8,021**
(1) Working capital detail, excluding MTM	
Receivables	(45)
Receivables from affiliates	(13)
Inventory	(15)
Other current assets	(451)
Accounts payable	47
Accounts payable to affiliates	124
Taxes accrued	(30)
Other current liabilities	(7)
	(390)
FFO / Debt	**22%**

FFO to Debt Calculation
Duke Energy Indiana
(in millions)

	Year Ended December 31, 2021 Actual
Cash From Operations	1,004
Adjust for Working Capital (1)	50
Coal ash ARO spend	67
Include Capitalized Interest as cost	17
Lease-imputed FFO adjustment (D&A)	16
Funds From Operations	**1,154**
Current maturities of LT debt	84
LT debt	4,089
LT debt payable to affiliates	150
CRC	196
Underfunded pension	114
Operating lease liabilities	54
Total Balance Sheet Debt (Including ST)	**4,687**
(1) Working capital detail, excluding MTM	
Receivables	(33)
Inventory	55
Other current assets	(181)
Accounts payable	76
Accounts payable to affiliates	8
Taxes accrued	12
Other current liabilities	13
	(50)
FFO / Debt	**25%**

FFO to Debt Calculation
Duke Energy Ohio
(in millions)

	Year Ended December 31, 2021 Actual
Cash From Operations	559
Adjust for Working Capital (1)	14
Coal Ash ARO spend	2
Include capitalized Interest as cost	(20)
Lease-imputed FFO adjustment (D&A)	10
Funds From Operations	**565**
Notes payable to affiliated companies	103
LT debt	3,168
LT debt payable to affiliates	25
CRC	153
Underfunded pension	90
Operating lease liabilities	19
Total Balance Sheet Debt (Including ST)	**3,558**
(1) Working capital detail, excluding MTM	
Receivables	6
Receivables from affiliates	(25)
Inventory	(6)
Other current assets	(60)
Accounts payable	38
Accounts payable to affiliates	(4)
Taxes accrued	26
Other current liabilities	11
	(14)
FFO / Debt	**16%**

FFO to Debt Calculation
Piedmont Natural Gas
(in millions)

	Year Ended December 31, 2021 Actual
Cash From Operations	391
Adjust for Working Capital (1)	138
Include Capitalized Interest as cost	(9)
Lease-imputed FFO adjustment (D&A)	6
Funds From Operations	**526**
Notes payable to affiliated companies	518
LT debt	2,968
Underfunded pension	3
Operating lease liabilities	19
Total Balance Sheet Debt (Including ST)	**3,508**
(1) Working capital detail, excluding MTM	
Receivables	(77)
Receivables from affiliates	(1)
Inventory	(40)
Other current assets	33
Accounts payable	(25)
Accounts payable to affiliates	(39)
Taxes accrued	37
Other current liabilities	(26)
	(138)
FFO / Debt	**15%**

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-2, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-2
Page 1 of 1

Request:

2. From 2014 through 2022, provide the Company's approved five-year capital plans.

    a. By business unit and by year, provide the capital cost break down that was approved in each five-year capital plan.

Response:

Please refer to DEP's response to PS DR 137-1, including the objections thereto, which are incorporated into this response by reference. DEP also objects to this request on the basis that it seeks eight years of data, which is unduly burdensome. Notwithstanding these objections, and without waiver thereof, the Company provides responsive information for the last five years. Please refer to the following four attachments:
PS DR 137-2 – DUK_2018 Slides
PS DR 137-2 – DUK_2019 Slides
PS DR 137-2 – DUK_2020 Slides
PS DR 137-2 – DUK_2021 Slides
Specifically, please reference the Capital Expenditures by Utility slide in the Earnings Review and Business Update presentations for the last four years, which can be found on the following slides:
2018: Slide 28
2019: Slide 26
2020: Slide 28
2021: Slide 34
The Company's Q4/2022 presentation, containing information for 2022, will be available after the Company's earnings call on February 9, 2023. Once available, the presentation may be accessed at https://investors.duke-energy.com/financials/quarterly-results/default.aspx.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-3, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-3
Page 1 of 1

Request:

3. Provide a general narrative of how the Company continually updates the five-year capital plan.
    a. List and describe what other capital plans the Company approves and monitors. For example, does the Company have a less than five-year capital plan approval process (e.g., two-year or one-year)?
    b. If the Company does have a less than five-year capital plan, please provide the approved capital plans by year from 2014 through 2022.

Response:

Please refer to DEP's response to PS DR 137-1, including the objections thereto, which are incorporated into this response by reference. Notwithstanding these objections, and without waiver thereof, the Company responds as follows:

The Company does not maintain a separate "less than five year" capital plan.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-4, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-4
Page 1 of 1

Request:

4. By year and by business unit, please provide the actual capital spend from 2014 through 2022.
    a. For any cost deviations greater than 5% from the five-year capital plan versus actual spend, please provide a general narrative that explains the overall cost deviation and describe if other capital projects had to be shifted, postponed, or even canceled.

Response:

Please see DEP's response to DR 137-1, including the objections thereto, which are incorporated into this response by reference.

Supplemental Response to PSDR 137-4
Docket No. E-2, Sub 1300

Duke Energy Progress		2018A		2018B
Nuclear & RRE		1,222		1,176
Transmission		245		226
Distribution		585		465
Other		152		180
Total Capital	**$**	**2,205**	**$**	**2,047**

Duke Energy Progress		2019A		2019B
Nuclear & RRE		846		794
Transmission		283		225
Distribution		683		608
Other		151		223
Total Capital	**$**	**1,962**	**$**	**1,850**

Duke Energy Progress		2020A		2020B
Nuclear & RRE		460		558
Transmission		269		268
Distribution		636		699
Other		142		181
Total Capital	**$**	**1,507**	**$**	**1,706**

Duke Energy Progress		2021A		2021B
Nuclear & RRE		541		533
Transmission		270		289
Distribution		634		652
Other		186		218
Total Capital	**$**	**1,631**	**$**	**1,692**

Duke Energy Progress		2022A		2022B
Nuclear & RRE		654		778
Transmission		365		392
Distribution		947		925
Other		184		313
Total Capital	**$**	**2,150**	**$**	**2,408**

Duke Energy Progress	Total 2018-2022A	Total 2018-2022B
Nuclear & RRE	3,724	3,839
Transmission	1,432	1,401
Distribution	3,485	3,348
Other	814	1,114

Total Capital	**$**	**9,455**	**$**	**9,702**

above such as coal ash closure spend and AFUDC debt. Additionally, actual versus buc
whereas the support provided for 137-2 is categorized based on growth versus maintena
capital spend other than Nuclear, RRE, Transmission and Distribution. This would incluc

	Variance (Over)/Under spend	% of Budget
	(46)	-4%
	(19)	-9%
	(121)	-26%
	28	16%
$	**(158)**	**-8%**

	Variance (Over)/Under spend	% of Budget
	(52)	-7%
	(57)	-25%
	(75)	-12%
	72	32%
$	**(112)**	**-6%**

	Variance (Over)/Under spend	% of Budget
	98	18%
	(1)	0%
	63	9%
	39	22%
$	**199**	**12%**

	Variance (Over)/Under spend	% of Budget
	(8)	-1%
	19	7%
	18	3%
	32	15%
$	**61**	**4%**

	Variance (Over)/Under spend	% of Budget
	123	16%
	27	7%
	(22)	-2%
	129	41%
$	**258**	**11%**

	Variance (Over)/Under spend	% of Budget
	115	3%
	(31)	-2%
	(137)	-4%
	300	27%

$	**247**	**3%**

dget tracking is performed at a total functional level
ance type spend. The category "Other" includes all
de spend such as new renewables projects, IT,

Primary Contributor to Variance > 5%

Increased outage restorations & veg management & timing of relocations

Increased outage restorations due to Hurricanes Florence & Michael & timing of AMI deployment

Project delays

Primary Contributor to Variance > 5%

Increased Nuclear maintenance

Project timing

Increased customer additions & timing of AMI deployment

Project cancellation & timing

Primary Contributor to Variance > 5%

Timing of Nuclear fuel & other projects

Timing of project spend

Timing of renewables & microgrid projects

Primary Contributor to Variance > 5%

Decreased spend & workplan

Decreased workplans & project delays

Primary Contributor to Variance > 5%

Department of Energy dry storage reimbursement

Project timing

Timing of new battery projects

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached supplemental response to NC Public Staff Data Request No. 137-4, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-4
Page 1 of 1

Request:

4. By year and by business unit, please provide the actual capital spend from 2014 through 2022.
   a. For any cost deviations greater than 5% from the five-year capital plan versus actual spend, please provide a general narrative that explains the overall cost deviation and describe if other capital projects had to be shifted, postponed, or even canceled.

Supplemental Response (Feb. 15, 2023):

Please refer to attachment "DEP_Supplemental Response to PSDR 137-4.xlsx".

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-5, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-5
Page 1 of 1

Request:

5. If the Company does not meet its five-year capital plan, please describe what actions the Company would take.
    a. If the Company under spends, provide and describe examples of what actions the Company has historically taken.
    b. If the Company over spends, provide and describe examples of what actions the Company has historically taken.
    c. Describe whether actions taken historically would or would not be relevant as part of the MYRP and its multiple rate years.

Response:

Please see DEP's response to PS DR 137-1, including the objections thereto, which are incorporated into this response by reference.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 20, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached supplemental response to NC Public Staff Data Request No. 137-5, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-5
Page 1 of 1

Request:

5. If the Company does not meet its five-year capital plan, please describe what actions the Company would take.
    a. If the Company under spends, provide and describe examples of what actions the Company has historically taken.
    b. If the Company over spends, provide and describe examples of what actions the Company has historically taken.
    c. Describe whether actions taken historically would or would not be relevant as part of the MYRP and its multiple rate years.

Supplemental Response (Feb. 20, 2023):

As explained in response to the February 9, 2023, Supplemental Response to PSDR 137-1, the Company's five-year capital plan is created at a point in time and is updated as circumstances dictate. For example, the Company may respond in the middle of a year to changing priorities that will cause overspend or underspend in that year (e.g. storm response). At the enterprise level, we use an established enterprise capital optimization ("ECO") process to address emergent and unplanned needs during a given year. This process provides a forum whereby functions within a jurisdiction can identify their budget gaps and ask other functions to respond to keep the overall enterprise plan intact. These forums have participation from our operational leaders and State Presidents who approve the functional five-year capital plans (i.e., for DEP, the North Carolina State President), which are then incorporated into the overall enterprise financial plan that is approved by senior leadership (including the CEO and CFO) and the Board of Directors by the end of the year.

Inter-year changes are also made to the five-year capital plan, due to timing variations where the Company may not be able to respond in a given year. In these cases, the ECO process will allocate higher or lower funding to the jurisdiction and reprioritize projects based on the new level of funding.

An essential factor in prioritizing work at the jurisdictional level is regulatory commitment. As discussed further in the supplemental response to 137-7&8, the MYRP construct introduces a new paradigm and when projects have been specifically approved in an MYRP, the Company intends to move forward with implementation subject to the discretion recognized by the Commission to modify MYRP projects for the benefit of customers.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-6, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-6
Page 1 of 1

Request:

6. Provide a general narrative of actions taken by the Company in the 2021, 2022, and 2023 five-year capital plans, given the passage of HB 951 and the Company requesting a MYRP.

Response:

Please see DEP's response to PS DR 137-1, including the objections thereto, which are incorporated into this response by reference. Notwithstanding these objections, and without waiver thereof, the Company responds as follows:

In connection with evaluation and refinement of the five-year capital plan, the prioritization process described in the response to DR 137-1 is managed within the confines of capital targets set at an enterprise level to optimize cash flow and balance sheet needs. The capital plan always considers new generation needs as typically dictated by the latest approved IRPs. With the passage of HB 951, estimated capital dollars have been allocated to fund future new generation to achieve carbon reduction targets. These capital dollars will continue to be refined and allocated to specific new generation projects based on outcomes and approvals in the Carbon Plan proceedings.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-7, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-7
Page 1 of 1

Request:

7. Describe the impacts of the Company's originally proposed 10-year Power Forward/Carolinas initiative on the five-year capital plan.

   a. Did the Company approve a five-year plan associated with the Power Forward/Carolinas programs?
      i. If not, please describe why not.
      ii. If so, please describe why the capital plan was approved prior to approval by either the NC or SC Commissions.
      iii. If so, please describe how the Company adjusted its five-year capital plan once the Power Forward/Carolinas initiative was modified/canceled/reduced in scope?

Response:

Please see responses to PS DR 137-1 and PS DR 137-6, including the objections thereto, which are incorporated into this response by reference. Notwithstanding these objections, and without waiver thereof, the Company responds as follows:

This question does not accurately reflect how the Company develops its five-year capital plan. As described in response to previous questions, the capital plan results from a top-down approach based upon enterprise targets. Previous inclusions (or exclusions) of Power Forward/Carolinas projects, or projects resulting from other prior Company initiatives, are irrelevant to this case. The way the Company prioritizes and, as necessary, re-prioritizes, capital spending plans is described in responses to previous questions.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 20, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached supplemental response to NC Public Staff Data Request No. 137-7, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-7
Page 1 of 1

Request:

7. Describe the impacts of the Company's originally proposed 10-year Power Forward/Carolinas initiative on the five-year capital plan.

   a. Did the Company approve a five-year plan associated with the Power Forward/Carolinas programs?
      i. If not, please describe why not.
      ii. If so, please describe why the capital plan was approved prior to approval by either the NC or SC Commissions.
      iii. If so, please describe how the Company adjusted its five-year capital plan once the Power Forward/Carolinas initiative was modified/canceled/reduced in scope?

Supplemental Response (Feb. 20, 2023):

As discussed, PBR (including the MYRP construct) presents a new paradigm for Commission-approval of forward looking capital investments. If the MYRP is approved by the Commission, the Company will move forward with execution of those projects as approved by the Commission and the execution of those projects will continue to be fully reflected in the capital plan. As was recognized by the Commission in the PBR rulemaking docket, the Company should appropriately retain the discretion to make changes to the MYRP projects where necessary for the benefit of customer and all such decisions will be reviewed in future rate cases from a prudence perspective. The Power Forward and Grid Improvement Plan were proposed initiatives that were fundamentally different than a Commission-approved slate of MYRP projects.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-8, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-8
Page 1 of 1

Request:

8. Describe the impacts of the Company's originally proposed Grid Improvement Plan on the five-year capital plan.

   a. Did the Company approve a five-year plan associated with the Grid Improvement programs?
      i. If not, please describe why not.
      ii. If so, please describe why the capital plan was approved prior to approval by either the NC or SC Commissions.
      iii. If so, please describe how the Company adjusted its five-year capital plan once the Grid Improvement Plan was modified/canceled/reduced in scope?

Response:

Please see DEP's responses to PS DR 137-1, 137-6, and 137-7, including the objections thereto, which are incorporated into this response by reference.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 20, 2023

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached supplemental response to NC Public Staff Data Request No. 137-8, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-8
Page 1 of 1

Request:

8. Describe the impacts of the Company's originally proposed Grid Improvement Plan on the five-year capital plan.

   a. Did the Company approve a five-year plan associated with the Grid Improvement programs?
      i. If not, please describe why not.
      ii. If so, please describe why the capital plan was approved prior to approval by either the NC or SC Commissions.
      iii. If so, please describe how the Company adjusted its five-year capital plan once the Grid Improvement Plan was modified/canceled/reduced in scope?

Supplemental Response (Feb. 20, 2023):

As discussed, PBR (including the MYRP construct) presents a new paradigm for Commission-approval of forward looking capital investments. If the MYRP is approved by the Commission, the Company will move forward with execution of those projects as approved by the Commission and the execution of those projects will continue to be fully reflected in the capital plan. As was recognized by the Commission in the PBR rulemaking docket, the Company should appropriately retain the discretion to make changes to the MYRP projects where necessary for the benefit of customer and all such decisions will be reviewed in future rate cases from a prudence perspective. The Power Forward and Grid Improvement Plan were proposed initiatives that were fundamentally different than a Commission-approved slate of MYRP projects.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-9, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-9
Page 1 of 1

Request:

9. List the year when DEP first identified and approved red zone upgrades in a five-year capital plan.

Response:

Please see DEP's responses to PS DR 137-1 and DR 137-6, including the objections thereto, which are incorporated into this response by reference. Notwithstanding these objections, and without waiver thereof, the Company responds as follows:

In connection with the prioritization process described in the response to PS DR 137-6 and given the outcome of the Carbon Plan order issued on December 30, 2022, the Company will proceed with constructing the red zone upgrades and formally including the necessary funding in the five-year capital plan as of 2022.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-10, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-10
Page 1 of 1

Request:

10. Provide a general narrative of whether, and if so, when, the Company included offshore wind and/or associated transmission work in a five-year capital plan.

Response:

Please see DEP's responses to PS DR 137-1 and DR 137-6, including the objections thereto, which are incorporated into this response by reference. Notwithstanding these objections, and without waiver thereof, the Company responds as follows:

In connection with the prioritization process described in the response to PS DR 137-6 and given the outcome of the Carbon Plan order issued on December 30, 2022, the Company will continue to study the three available offshore wind leases and related onshore transmission infrastructure and will formally include any necessary funding in the five-year capital plan at the appropriate time. Additional capital funding for offshore wind and the related onshore transmission will be evaluated and funded as determined, in part, by future Carbon Plan proceedings.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-11, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-11
Page 1 of 1

Request:

11. Given the impacts of the Moore County substation attacks, please provide a narrative of how reactive/preventative measures may require a change in the current five-year capital plan?
    a. When does the Company expect to update the current five-year capital plan to account for potential reactive/preventative measures to mitigate substation risks.

Response:

Please see DEP's responses to PS DR 137-1 and DR 137-6, including the objections thereto, which are incorporated into this response by reference. Notwithstanding these objections, and without waiver thereof, the Company responds as follows:

In connection with the prioritization process described in the response to PS DR 137-6, the Company is evaluating the need for reactive/preventative measures that may require capital investment in light of the Moore County substation attacks. The capital plan will be adjusted and reprioritized as necessary to fund any additional capital investment.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-12, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-12
Page 1 of 1

Request:

12. Given overall generating unit performance during December 2022 Winter Storm Elliot, please provide a narrative of how reactive/preventative measures to ensure unit availability and/or prevention of unit derates may impact the current five-year capital plan?
    a. When does the Company expect to update the current five-year capital plan to account for potential reactive/preventative measures to prevent future occurrences of unit availability and prevention of unit derates during extreme weather events.

Response:

Please see DEP's responses to PS DR 137-1 and DR 137-6, including the objections thereto, which are incorporated into this response by reference. Notwithstanding these objections, and without waiver thereof, the Company responds as follows:

In connection with the prioritization process described in the response to PS DR 137-6, the Company is evaluating the need for reactive/preventative measures that may require capital investment in light of the December 2022 Winter Storm Elliot. The capital plan will be adjusted and reprioritized as necessary to fund any additional capital investment.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-13, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-13
Page 1 of 1

Request:

13. Describe and list all new changes/upgrades affecting Company-owned generating unit performance approved in the current five-year capital plan.
    a. Include the generation type, expected/approved budget, estimated nameplate rating, and fuel type.

Response:

Please see DEP's responses to PS DR 137-1 and DR 137-6, including the objections thereto, which are incorporated into this response by reference. Notwithstanding these objections, and without waiver thereof, the Company responds as follows:

Certain new changes/upgrades affecting Company-owned generating unit performance have been included in the MYRP filing and are also included in the current five-year capital plan. For detail on these MYRP projects please see attachment "DEP DR 137-13 Support". Note these projects are expected to provide incremental increases in unit capacity; however, actual increases will be determined based on performance testing. The Tillery projects are expected to increase the nameplate rating and capacity by about 3-5 MW. The Smith CTs could increase capacity by about 5-10 MW but would likely not increase the nameplate rating.

Any additional forecasted capital projects not included in the MYRP filing are outside the scope of this rate case.

Funding Project	Generation Type	Current Name Plate Rating MW
TL010017	Hydro	22
TL030005	Hydro	22
RM040038	CT	199.4
RM060044	CT	199.4

Project Scope/Description	Capital ($ in millions)
Tillery Unit 1 life extension project	16
Replace Tillery Unit 3 turbine runner	18
GE Advance Gas Path peaker upgrade for Smith Combustion Turbine Unit 4	6
GE Advance Gas Path peaker upgrade for Smith Combustion Turbine Unit 6	5

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-14, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-14
Page 1 of 1

Request:

14. Describe how the five-year capital plan provides input to and/or considers annual operation and maintenance expenses.
    a. Would the five-year capital plan inform, evaluate, require increases, or require decreases to annual O&M costs/expenditures? If so, please provide examples.

Response:

Please see DEP's response to PS DR 137-1, including the objections thereto, which are incorporated into this response by reference. Notwithstanding these objections, and without waiver thereof, the Company responds as follows:

The five-year capital plan can influence the annual O&M costs/expenditures as certain capital projects funded in the five-year capital plan could require incremental O&M either during construction or after in-service. For example, new generation assets could require incremental O&M after in-service to operate the asset. Each function is responsible for identifying any capital projects requiring incremental O&M and communicating the necessary O&M amounts to their respective Finance contacts. Incremental project O&M is evaluated and prioritized against other O&M to include in the O&M budget/five-year plan.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 1, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-15, was provided to me by the following individual(s): Joanna Cormier, Director of Carolinas Forecasting & Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-15
Page 1 of 1

Request:

15. Provide a general narrative that describes the Company's annual O&M budgeting and approval process?
    a. Does the Company have a five-year plan for O&M similar to the capital plan process, or is it a one- or two-year plan?
    b. Please provide the O&M plan approvals from 2014-2022.
    c. When are the O&M plans approved?
    d. Who approves the O&M plans?
        i. Include all layers of management approval required from plan development to final sign off.

Response:

Please see DEP's response to PS DR 137-1, including the objections thereto, which are incorporated into this response by reference. Like the previous questions, which are focused on DEP's capital planning process, this request appears to be premised upon the incorrect supposition that the Company's annual O&M budgeting and approval process is a project management tool. Rather, the Company's five-year O&M plan is a top-down financial planning and forecast tool that is continuously evaluated and refined. O&M is approved as a part of the overall financial plan by senior leadership (including the CEO and CFO) and the Board of Directors by the end of the year. There is no formal documentation of O&M approvals as the financial plan is approved during in-person meetings. As with any planning tool, the Company's O&M plans must be flexible so as to be able to deal with emergent events, which may require re-prioritization in order to align plans with Company objectives.

Accordingly, each subpart to this question begins from an inaccurate premise, and thus seeks information irrelevant to any issue in this case. Detailed information concerning O&M associated with the capital projects included in the Company's MYRP has been provided in connection with the Company's Application and direct testimony, as well as data requests propounded with respect to those projects.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 137

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: January 31, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 137-16, was provided to me by the following individual(s): Christine Perciaccante, CW-Professional, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 137
DEP Docket No. E2, Sub 1300
Item No. 137-16
Page 1 of 1

Request:

16. Please provide a general narrative that describes how the Company evaluates non-fuel O&M monetary amounts included as line items in a general rate case versus what is actually spent in the following years after the general rate case.
    a. Provide examples per business unit, notably generation and T&D, of the amounts included as line items in the previous two general rate cases versus costs that were incurred following the general rate case.
    b. Describe whether the Company considers costs included as line items in a general rate case for non-fuel O&M costs as an absolute amount to spend, or whether the Company considers them to be a stochastic spend subject to dynamic and changing conditions.

Response:

DEP objects to this request on the grounds that it is irrelevant to the issues in this case and on the grounds that, as stated, the request assumes an "either/or" approach to non-fuel O&M spend when neither of the stated options is applicable to the Company's practice. Notwithstanding these objections, and without waiver thereof, DEP responds as follows:

The Company does not evaluate non-fuel O&M monetary amounts included as line items in a general rate case versus what is actually spent in the following years.

a. See response above. In addition, comparing Base Rate O&M to Actual Total O&M is an apples and oranges comparison, in that while a rate case revenue requirement starts with a historical per book test year and Cost of Service which is at a functional level, there are numerous proforma adjustments which are subsequently made, and those adjustments are not at a functional or business unit level. For example, one of the material adjustments to O&M in a rate case is to remove O&M recovered through non-fuel riders, and this results in the removal of over $100 MM in O&M related to various riders.

b. DEP considers the indicated costs neither as an absolute amount to spend nor as stochastic spend. Such costs are incurred considering the prevailing conditions at the time.

Attachment A

Supplemental Responses – PSDR Set 137
Docket No. E-2, Sub 1300

Supplemental Response to 137-5

As explained in response to the February 9, 2023, Supplemental Response to PSDR 137-1, the Company's five-year capital plan is created at a point in time and is updated as circumstances dictate. For example, the Company may respond in the middle of a year to changing priorities that will cause overspend or underspend in that year (e.g. storm response). At the enterprise level, we use an established enterprise capital optimization ("ECO") process to address emergent and unplanned needs during a given year. This process provides a forum whereby functions within a jurisdiction can identify their budget gaps and ask other functions to respond to keep the overall enterprise plan intact. These forums have participation from our operational leaders and State Presidents who approve the functional five-year capital plans (*i.e.,* for DEP, the North Carolina State President), which are then incorporated into the overall enterprise financial plan that is approved by senior leadership (including the CEO and CFO) and the Board of Directors by the end of the year.

Inter-year changes are also made to the five-year capital plan, due to timing variations where the Company may not be able to respond in a given year. In these cases, the ECO process will allocate higher or lower funding to the jurisdiction and reprioritize projects based on the new level of funding.

An essential factor in prioritizing work at the jurisdictional level is regulatory commitment. As discussed further in the supplemental response to 137-7&8, the MYRP construct introduces a new paradigm and when projects have been specifically approved in an MYRP, the Company intends to move forward with implementation subject to the discretion recognized by the Commission to modify MYRP projects for the benefit of customers.

Supplemental Response to 137-10

There are no projects for offshore wind and/or associated transmission in the MYRP. In response to the Carbon Plan Order, a small amount of capital totaling less than 1% of DEP's total 5-year capital plan has been allocated for offshore wind as the Company continues to evaluate a variety of generation sources as the Carbon Plan IRP is developed. At this point in time, there are no discrete, identifiable wind projects included in the enterprise-level five-year capital plan.

Supplemental Response to 137-7 and 8

As discussed, PBR (including the MYRP construct) presents a new paradigm for Commission-approval of forward-looking capital investments. If the MYRP is approved by the Commission, the Company will move forward with execution of those projects as approved by the Commission and the execution of those projects will continue to be fully reflected in the capital plan. As was recognized by the Commission in the PBR rulemaking docket, the Company should appropriately retain the discretion to make changes to the MYRP projects where necessary for the benefit of customer and all such decisions will be reviewed in future rate cases from a prudence perspective. The Power Forward and Grid Improvement Plan were proposed initiatives that were fundamentally different than a Commission-approved slate of MYRP projects.

Duke Energy Progress
Docket No. E-2, Sub 1300
Public Staff Data Request No. 138
Date Sent: January 20, 2023
Date Requested: January 30, 2023

Public Staff Technical Contact: **Dustin Metz**
Phone #: (919) 733-1513
Email: dustin.metz@psncuc.nc.gov

Public Staff Legal Contact: **Robert Josey**
Phone #: (919) 733-0976
Email: robert.josey@psncuc.nc.gov

Topic: Cost Saving Measures and the Test Year

Please provide any available responses electronically in a searchable native electronic format. If in Excel format, be sure to include all working formulas. In addition, please include (1) the name and title of the individual who has the responsibility for the subject matter addressed therein, and (2) the identity of the person making the response by name, occupation, and job title.

PDF
Duke Energy braces for Covid-19 impact.p

1. In 2020, news agencies reported that Duke Energy planned for $450 million in cost cuts [see the attached document for one such report]. Please answer the following items as they relate to Duke Energy Progress and the $450M in cost cuts, as well as any other cost saving measures.

   a. Provide a detailed narrative and a list of specific examples of cost cuts that were implemented across each business entity in DEP (e.g., transmission, distribution, nuclear, fossil, etc.).

   b. List the total cost cuts for DEP.

   c. List the total enterprise-wise cost cuts at the corporate or enterprise level (Duke Energy Corporate and/or enterprise costs) that occurred but were not assigned to DEP and an accompanying narrative that describes why they were not applied.

   d. For each cost cut made in DEP, provide a narrative on the duration or measure of the cost cut and when, if at all, it was lifted.

   e. Provide a narrative of how DEP “more efficiently schedul[ed] plant outages.”

f. Provide a detailed narrative of each DEP plant scheduled outage that was impacted by this more efficient plant outage management and what functions/scope/projects of the outage were reduced.

   i. If project scope was reduced from the originally planned outage or the previous years' expected outage plan, provide a narrative discussing if and when the work was delayed/rescheduled to a future outage.

      i. List when the delayed work was ultimately completed.

   ii. Did the delayed work from the 2020 outage schedules, as part of the cost cuts by the Company, cause work to be moved to calendar year 2021?

      i. If so, please list all incremental costs in the 2021 test year that were the result of outage work delayed/rescheduled from the 2020 calendar year.

g. Based on Company responses to PS DR 21-2 (O&M by Plant, O&M costs excluding fuel costs), the costs per plant in 2020 were generally less than the previous year. Please provide context on the Company's reduced O&M spending at generation plants and how that was or was not related to Duke Energy's overall cost cuts prescribed in 2020.

   Note: The Public Staff understands that certain capital projects in nuclear have contributed to ongoing O&M reductions.

   i. To the extent possible, please quantify the reductions in O&M (non-fuel related) spending as a function of reduced power demand, causing a lesser amount of total energy that needed to be generated by the DEP system. Please list any specific metrics to which this may or may not be applicable on a $/MWh basis and how it compares to other years.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 138

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 6, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 138-1, was provided to me by the following individual(s): Joanna Cormier, Director Carolinas Forecasting and Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 138
DEP Docket No. E2, Sub 1300
Item No. 138-1
Page 1 of 3

Request:

1. In 2020, news agencies reported that Duke Energy planned for $450 million in cost cuts [see the attached document for one such report]. Please answer the following items as they relate to Duke Energy Progress and the $450M in cost cuts, as well as any other cost saving measures.
    a. Provide a detailed narrative and a list of specific examples of cost cuts that were implemented across each business entity in DEP (e.g., transmission, distribution, nuclear, fossil, etc.).
    b. List the total cost cuts for DEP.
    c. List the total enterprise-wise cost cuts at the corporate or enterprise level (Duke Energy Corporate and/or enterprise costs) that occurred but were not assigned to DEP and an accompanying narrative that describes why they were not applied.
    d. For each cost cut made in DEP, provide a narrative on the duration or measure of the cost cut and when, if at all, it was lifted.
    e. Provide a narrative of how DEP "more efficiently schedul[ed] plant outages."
    f. Provide a detailed narrative of each DEP plant scheduled outage that was impacted by this more efficient plant outage management and what functions/scope/projects of the outage were reduced.
        i. If project scope was reduced from the originally planned outage or the previous years' expected outage plan, provide a narrative discussing if and when the work was delayed/rescheduled to a future outage.
            1. List when the delayed work was ultimately completed.
        ii. Did the delayed work from the 2020 outage schedules, as part of the cost cuts by the Company, cause work to be moved to calendar year 2021?
            1. If so, please list all incremental costs in the 2021 test year that were the result of outage work delayed/rescheduled from the 2020 calendar year.
    g. Based on Company responses to PS DR 21-2 (O&M by Plant, O&M costs excluding fuel costs), the costs per plant in 2020 were generally less than the previous year. Please provide context on the Company's reduced O&M spending at generation plants and how that was or was not related to Duke Energy's overall cost cuts prescribed in 2020.
    Note: The Public Staff understands that certain capital projects in nuclear have contributed to ongoing O&M reductions.
        i. To the extent possible, please quantify the reductions in O&M (non-fuel related) spending as a function of reduced power demand, causing a lesser amount of total energy that needed to be generated by the DEP system. Please list any specific metrics to which this may or may not be applicable on a $/MWh basis and how it compares to other years.

Response:

1a. DEP objects to this set of requests, including this subpart, on the grounds that these questions appear to be premised upon the incorrect supposition that the Company's cost reductions during 2020 unreasonably impacted the test period in this rate proceeding. Rather, the cost savings initiative implemented in 2020 (during an unprecedented pandemic) is consistent with the Company's longstanding prudent and reasonable utility planning practices. Questions that seek detailed information on specific cost cuts, particularly as they relate to expenses not in the test period, are not relevant to this proceeding and are unduly burdensome. Notwithstanding these objections, and without waiver thereof, the Company responds as follows:

Cost management is a normal course of business for the Company and was not unique to the cost cutting performed in 2020. The Company continuously strives to improve upon and refine cost management. To that end, the Company has reduced costs, on average, by around 1% annually since 2016. And while the COVID-19 pandemic undoubtedly presented the Company (and virtually all businesses) with unprecedented challenges, it also gave the Company a chance to further refine its cost management processes and re-examine the versatility of its work force and its cost structure.
The Company's 2020 cost savings initiative that resulted from this evaluation identified approximately $450MM in cost savings. Most of the savings associated with this initiative have extended beyond 2020 and the test year in this proceeding. In fact, the largest portion of the $450MM in cost savings (~$200MM; DEP NC retail allocation is $100MM) are sustainable O&M savings resulting from the Company reexamining its longstanding practices and cost structure associated with items such as real estate, employee expenses and technological advancements.

Other sustainable savings contained in the 2020 cost savings initiative include non-O&M expenses (e.g. issuing debt at lower interest rates and tax optimization), which benefit the test year. Only a small portion of the cost savings implemented in 2020 were "tactical" in nature (e.g. hiring freezes, lower variable compensation and timing of outages). These savings were associated with a decline in the Company's top line revenues (Commercial and Industrial) due to the pandemic, but they are more than offset by the sustainable savings described above.

Please refer to Slide 10 of the Fourth Quarter 2020 Earnings Review And Business Update for a graphical depiction of the breakdown in cost savings. The presentation may be accessed at
https://s201.q4cdn.com/583395453/files/doc_presentation/2021/02/q4-2020-slides.pdf

In addition, please note that DEP's rate case filing includes several adjustments to test year expenses to minimize their impact on customer rates. For example, the following adjustments were made to test year expenses:
• salaries & wages are annualized as of the capital cutoff date (March 2023), thus normalizing any abnormalities in the test year.

• incentive compensation is adjusted to 100% of target, so variations in compensation do not impact customer rates.
• normalized nuclear outage expense
• adjusted test year revenues and variable O&M to normalize sales for weather and to annualize sales based on number of customers as of the capital cutoff (March 2023) and usage per customer for the 12 months leading up to the capital cutoff. Also note that during 2020, DEP's weather-normalized sales volumes were around 2% lower than 2019.

Accordingly, the insinuation that test year costs have been manipulated is without any foundation.
1b. Please refer to the Company's response to PS DR 138-1(a.).
1c. Please refer to the Company's response to PS DR 138-1(a.).
1d. Please refer to the Company's response to PS DR 138-1(a.).
1e. Please refer to DEP's response to PS DR 138-1(a.).
1f. Please refer to DEP's response to PS DR 138-1(a.).
1f(i). Please refer to DEP's response to PS DR 138-1(a.), including the objections thereto, which are incorporated into this response by reference. Notwithstanding these objections, and without waiver thereof, the Company responds as follows:
Work scope was reduced at the routine work order level within each station's work management system. Work orders that were deferred would be scheduled at the next available outage window which would have been 2021 or 2022. This is typically how generation manages cost and balances it with risks to reliability of the units.
1f.(i)(i). See above. Each outage season is prioritized based on what has happened since the last outage and work is prioritized based on available funding and priority.
1.f.(ii). No.

1.f.(ii)(i). N/A
1(g). Please refer to DEP's response to PS DR 138-1(a.), including the objections thereto, which are incorporated into this response by reference. Notwithstanding these objections, and without waiver thereof, the Company responds as follows:
Reduced spending was simply due to the normal scheduling of outages. Some years plants have outages and other years they do not.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 138

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 14, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached supplemental response to NC Public Staff Data Request No. 138-1, was provided to me by the following individual(s): Joanna Cormier, Director Carolinas Forecasting and Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 138
DEP Docket No. E2, Sub 1300
Item No. 138-1
Page 1 of 3

Request:

1. In 2020, news agencies reported that Duke Energy planned for $450 million in cost cuts [see the attached document for one such report]. Please answer the following items as they relate to Duke Energy Progress and the $450M in cost cuts, as well as any other cost saving measures.
   a. Provide a detailed narrative and a list of specific examples of cost cuts that were implemented across each business entity in DEP (e.g., transmission, distribution, nuclear, fossil, etc.).
   b. List the total cost cuts for DEP.
   c. List the total enterprise-wise cost cuts at the corporate or enterprise level (Duke Energy Corporate and/or enterprise costs) that occurred but were not assigned to DEP and an accompanying narrative that describes why they were not applied.
   d. For each cost cut made in DEP, provide a narrative on the duration or measure of the cost cut and when, if at all, it was lifted.
   e. Provide a narrative of how DEP "more efficiently schedul[ed] plant outages."
   f. Provide a detailed narrative of each DEP plant scheduled outage that was impacted by this more efficient plant outage management and what functions/scope/projects of the outage were reduced.
      i. If project scope was reduced from the originally planned outage or the previous years' expected outage plan, provide a narrative discussing if and when the work was delayed/rescheduled to a future outage.
         1. List when the delayed work was ultimately completed.
      ii. Did the delayed work from the 2020 outage schedules, as part of the cost cuts by the Company, cause work to be moved to calendar year 2021?
         1. If so, please list all incremental costs in the 2021 test year that were the result of outage work delayed/rescheduled from the 2020 calendar year.
   g. Based on Company responses to PS DR 21-2 (O&M by Plant, O&M costs excluding fuel costs), the costs per plant in 2020 were generally less than the previous year. Please provide context on the Company's reduced O&M spending at generation plants and how that was or was not related to Duke Energy's overall cost cuts prescribed in 2020.
   Note: The Public Staff understands that certain capital projects in nuclear have contributed to ongoing O&M reductions.
      i. To the extent possible, please quantify the reductions in O&M (non-fuel related) spending as a function of reduced power demand, causing a lesser amount of total energy that needed to be generated by the DEP system. Please list any specific metrics to which this may or may not be applicable on a $/MWh basis and how it compares to other years.

Supplemental Response (2/14/23):

Supplemental response for subparts a – d.

See attached for a summary chart comparing, by function, budgeted O&M spend for 2020 compared to actual. In addition, the chart identifies the key drivers of such variances.

The Company hereby withdraws its objection but clarifies its response as follows. The Company does not maintain the requested information in the manner of organization requested by Public Staff. As previously explained, the Company maintains a consistent focus on managing O&M costs for the benefit of customers. Such O&M management efforts were planned for 2020 in the ordinary course even prior to the unforeseen circumstance of a global pandemic. While the chart captures summary level key drivers of the total reduced 2020 O&M spend (relative to budget), it is not consistent with the Company's internal practices to specifically track every cost not incurred or to differentiate any cost savings (relative to budget) between O&M reductions that would have occurred in the ordinary course and those that were in some form or fashion informed by the unforeseen circumstances of 2020. Instead, differences between budgeted and actual costs are assessed on an overall basis (see also the Company's responses to PSDR 162-2 through 5). Nor does the Company in the ordinary course track O&M costs not incurred in order to assess if such O&M cost is incurred in the future. As previously explained, cost reductions in 2020 that were sustainable have been carried forward and are embedded in the 2021 test period while those reductions that were not sustainable did not carry forward in 2021. However, the Company does not separately track those cost reductions that were sustainable; instead, it was expected that the business functions would accommodate any such costs within their 2021 budget.

Supplemental response for subparts e-f.

The Company hereby withdraws its objection but clarifies its response as follows. As is explained in more detail below, there were no planned outages in DEP for nuclear or RRE generation that were deferred from 2020 into 2021.

Similar to the narrative above, the Company does not maintain the requested information in the manner of organization requested by Public Staff. Specifically, the Company maintains a consistent focus on managing O&M costs for the benefit of customers and this includes efforts to optimize planned outages. As such, the efforts in 2020 to continue to optimally implement planned outages was simply an extension of efforts already underway and the Company does not track or account for the results of such efforts in a way to distinguish between efficiencies that would have occurred in the ordinary course and those that were in some form or fashion informed by the unforeseen circumstances of 2020.

Nuclear

The schedule for nuclear refueling outages was not impacted or revised related to the pandemic or other circumstance in 2020. Nuclear completed its full planned outage work scope in 2020

As a matter of course, Nuclear remains focused on the efficient scheduling of refueling outages to maximize the benefits to customers of nuclear generation's relatively stable and lower fuel cost, and the availability of both Company and external labor resources required for efficient execution of refueling outage work activities. The schedules for nuclear

North Carolina Public Staff
Data Request No. 138
DEP Docket No. E2, Sub 1300
Item No. 138-1

refueling outages are driven by the need to refuel and to some extent, regulatory drivers. The Company's nuclear plants continued to operate as baseload units during the pandemic, and nuclear output was not curtailed due to the reduction in load associated with the economic impacts of the pandemic.
The safety and reliability of the nuclear units is paramount in all decisions. The majority of the O&M reductions for Nuclear in 2020 resulted from efficiencies gained following the late 2019 reorganization where some staffing reductions were realized. These staffing reductions were enabled by streamlining work processes, eliminating unnecessary work, and gaining efficiencies from innovation and automation. Collectively, these actions afforded the opportunity to streamline certain functions within Nuclear. Such efforts are ongoing. While the Company saw reduced load demand in relation to the pandemic, the nuclear units continued to operate as baseload units. Collectively, there have been numerous Nuclear capital investments and innovation enabling projects that supported the Company's ability to re-evaluate Nuclear staffing and organization. However, the Nuclear SOCA/EWAS projects implemented across the fleet did provide for reduction in security headcounts.

RRE
The Company continually seeks to manage O&M costs across all plants for the benefit of customers. The majority of the changes from 2019 to 2020 were due to (1) the closing of the Asheville Coal Plant, (2) Richmond station having major outages in 2019 but not in 2020, and (3) 60% reduction in generation at Mayo, which lowered operation expenses.
For DEP, the following outage start dates were delayed due to the COVID-19 pandemic, but all were completed in 2020 and, in each case, the full planned work scope was completed.

- Darlington U12 delayed from 4/12 until 7/13. Planned work scope completed.
- Darlington U13 delayed from 4/12 until 7/12. Planned work scope completed.
- HF Lee CC delayed from 5/2 until 6/5. Planned work scope completed.
- Smith CT6 delayed from 4/4 until 10/17. Planned work scope completed.
- Smith CT4 delayed from 5/1 until 7/11. Planned work scope completed.
- Smith PB4 delayed from 3/6 until 9/11. Planned work scope completed.

Supplemental response for subpart g.
As explained above, the Company does not keep records that would distinguish between O&M cost reductions arising from the Company's efforts in the ordinary course to manage O&M versus those that were in any form or fashion arguably attributable to the specific circumstances of 2020. The Company also does not have any estimate of the extent to which O&M reductions can be tied to reduced power demand.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 138

Docket No. E-2, Sub 1300

Date of Request: January 20, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached supplemental response to NC Public Staff Data Request No. 138-1, was provided to me by the following individual(s): Joanna Cormier, Director Carolinas Forecasting and Planning, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 138
DEP Docket No. E2, Sub 1300
Item No. 138-1
Page 1 of 3

Request:

1. In 2020, news agencies reported that Duke Energy planned for $450 million in cost cuts [see the attached document for one such report]. Please answer the following items as they relate to Duke Energy Progress and the $450M in cost cuts, as well as any other cost saving measures.
    a. Provide a detailed narrative and a list of specific examples of cost cuts that were implemented across each business entity in DEP (e.g., transmission, distribution, nuclear, fossil, etc.).
    b. List the total cost cuts for DEP.
    c. List the total enterprise-wise cost cuts at the corporate or enterprise level (Duke Energy Corporate and/or enterprise costs) that occurred but were not assigned to DEP and an accompanying narrative that describes why they were not applied.
    d. For each cost cut made in DEP, provide a narrative on the duration or measure of the cost cut and when, if at all, it was lifted.
    e. Provide a narrative of how DEP "more efficiently schedul[ed] plant outages."
    f. Provide a detailed narrative of each DEP plant scheduled outage that was impacted by this more efficient plant outage management and what functions/scope/projects of the outage were reduced.
        i. If project scope was reduced from the originally planned outage or the previous years' expected outage plan, provide a narrative discussing if and when the work was delayed/rescheduled to a future outage.
            1. List when the delayed work was ultimately completed.
        ii. Did the delayed work from the 2020 outage schedules, as part of the cost cuts by the Company, cause work to be moved to calendar year 2021?
            1. If so, please list all incremental costs in the 2021 test year that were the result of outage work delayed/rescheduled from the 2020 calendar year.
    g. Based on Company responses to PS DR 21-2 (O&M by Plant, O&M costs excluding fuel costs), the costs per plant in 2020 were generally less than the previous year. Please provide context on the Company's reduced O&M spending at generation plants and how that was or was not related to Duke Energy's overall cost cuts prescribed in 2020.
    Note: The Public Staff understands that certain capital projects in nuclear have contributed to ongoing O&M reductions.
        i. To the extent possible, please quantify the reductions in O&M (non-fuel related) spending as a function of reduced power demand, causing a lesser amount of total energy that needed to be generated by the DEP system. Please list any specific metrics to which this may or may not be applicable on a $/MWh basis and how it compares to other years.

Supplemental Response (2/14/23):

Supplemental response for subparts a – d.

See attached for a summary chart comparing, by function, budgeted O&M spend for 2020 compared to actual. In addition, the chart identifies the key drivers of such variances.

The Company hereby withdraws its objection but clarifies its response as follows. The Company does not maintain the requested information in the manner of organization requested by Public Staff. As previously explained, the Company maintains a consistent focus on managing O&M costs for the benefit of customers. Such O&M management efforts were planned for 2020 in the ordinary course even prior to the unforeseen circumstance of a global pandemic. While the chart captures summary level key drivers of the total reduced 2020 O&M spend (relative to budget), it is not consistent with the Company's internal practices to specifically track every cost not incurred or to differentiate any cost savings (relative to budget) between O&M reductions that would have occurred in the ordinary course and those that were in some form or fashion informed by the unforeseen circumstances of 2020. Instead, differences between budgeted and actual costs are assessed on an overall basis (see also the Company's responses to PSDR 162-2 through 5). Nor does the Company in the ordinary course track O&M costs not incurred in order to assess if such O&M cost is incurred in the future. As previously explained, cost reductions in 2020 that were sustainable have been carried forward and are embedded in the 2021 test period while those reductions that were not sustainable did not carry forward in 2021. However, the Company does not separately track those cost reductions that were sustainable; instead, it was expected that the business functions would accommodate any such costs within their 2021 budget.

Supplemental response for subparts e-f.

The Company hereby withdraws its objection but clarifies its response as follows. As is explained in more detail below, there were no planned outages in DEP for nuclear or RRE generation that were deferred from 2020 into 2021.

Similar to the narrative above, the Company does not maintain the requested information in the manner of organization requested by Public Staff. Specifically, the Company maintains a consistent focus on managing O&M costs for the benefit of customers and this includes efforts to optimize planned outages. As such, the efforts in 2020 to continue to optimally implement planned outages was simply an extension of efforts already underway and the Company does not track or account for the results of such efforts in a way to distinguish between efficiencies that would have occurred in the ordinary course and those that were in some form or fashion informed by the unforeseen circumstances of 2020.

Nuclear

The schedule for nuclear refueling outages was not impacted or revised related to the pandemic or other circumstance in 2020. Nuclear completed its full planned outage work scope in 2020

As a matter of course, Nuclear remains focused on the efficient scheduling of refueling outages to maximize the benefits to customers of nuclear generation's relatively stable and lower fuel cost, and the availability of both Company and external labor resources required for efficient execution of refueling outage work activities. The schedules for nuclear refueling outages are driven by the need to refuel and to some extent, regulatory drivers. The Company's nuclear plants continued to operate as baseload units during the pandemic, and nuclear output was not curtailed due to the reduction in load associated with the economic impacts of the pandemic.

The safety and reliability of the nuclear units is paramount in all decisions. The majority of the O&M reductions for Nuclear in 2020 resulted from efficiencies gained following the late 2019 reorganization where some staffing reductions were realized. These staffing reductions were enabled by streamlining work processes, eliminating unnecessary work, and gaining efficiencies from innovation and automation. Collectively, these actions afforded the opportunity to streamline certain functions within Nuclear. Such efforts are ongoing. While the Company saw reduced load demand in relation to the pandemic, the nuclear units continued to operate as baseload units. Collectively, there have been numerous Nuclear capital investments and innovation enabling projects that supported the Company's ability to re-evaluate Nuclear staffing and organization. However, the Nuclear SOCA/EWAS projects implemented across the fleet did provide for reduction in security headcounts.

RRE

The Company continually seeks to manage O&M costs across all plants for the benefit of customers. The majority of the changes from 2019 to 2020 were due to (1) the closing of the Asheville Coal Plant, (2) Richmond station having major outages in 2019 but not in 2020, and (3) 60% reduction in generation at Mayo, which lowered operation expenses. For DEP, the following outage start dates were delayed due to the COVID-19 pandemic, but all were completed in 2020 and, in each case, the full planned work scope was completed.

- Darlington U12 delayed from 4/12 until 7/13. Planned work scope completed.
- Darlington U13 delayed from 4/12 until 7/12. Planned work scope completed.
- HF Lee CC delayed from 5/2 until 6/5. Planned work scope completed.
- Smith CT6 delayed from 4/4 until 10/17. Planned work scope completed.
- Smith CT4 delayed from 5/1 until 7/11. Planned work scope completed.
- Smith PB4 delayed from 3/6 until 9/11. Planned work scope completed.

Supplemental response for subpart g.

As explained above, the Company does not keep records that would distinguish between O&M cost reductions arising from the Company's efforts in the ordinary course to manage O&M versus those that were in any form or fashion arguably attributable to the specific circumstances of 2020. The Company also does not have any estimate of the extent to which O&M reductions can be tied to reduced power demand.

Supplemental Response to PSDR 138
Docket No. E-2, Sub 1300

Duke Energy Progress	2020A	2020B
Nuclear	472	492
RRE	127	149
Transmission	41	47
Distribution	106	120
Corporate	222	231
Other	383	375
Total O&M	**$ 1,350**	**$ 1,414**

Variance (Over)/Under spend		% of Budget	Primary Contributor to Variance
	20	4%	Labor
	22	15%	Base maintenance & labor
	6	13%	Non-routine maintenance & project O&M
	13	11%	Project O&M
	9	4%	Labor
	(7)	-2%	Storms
$	**63**	**4%**	

Additional Detail

Nuclear implemented a temporary hiring freeze in 2020 to manage costs through attrition and prior staffing reductions. However, hiring began again in 2021 as the reduced staffing levels were not sustainable for the long term.

RRE re-allocated budget funds to DEC in accordance with their processes of managing the business at a functional level. RRE did see some delays in outages from the spring to the fall due to COVID; however, these delays did not impact the total DEP 2020 outage schedule or spend.

Transmission did not cut any of its base or scheduled maintenance in 2020. However, it did reduce its budget in 2020 for non-routine maintenance which would have been used to address emerging or opportunistic items. Additionally, Transmission saw reductions in capital spend which resulted in reduced project O&M.

Delivery reduced capital spend in 2020 and, as a result, saw reduced project O&M. Additionally, Delivery saw underspend on communication and technology projects.

Corporate implemented a hiring freeze in 2020 to manage costs through attrition and prior staffing reductions. However, hiring began again in 2021 as the reduced staffing levels were not sustainable for the long term.

Supplemental Response to PSDR 138
Docket No. E-2, Sub 1300

Duke Energy Progress	2020A	2020B
Nuclear	472	492
RRE	127	149
Transmission	41	47
Distribution	106	120
Corporate	222	231
Other	383	375
Total O&M	**$ 1,350**	**$ 1,414**

	Variance (Over)/Under spend	% of Budget	Primary Contributor to Variance
	20	4%	Labor
	22	15%	Base maintenance & labor
	6	13%	Non-routine maintenance & project O&M
	13	11%	Project O&M
	9	4%	Labor
	(7)	-2%	Storms
$	**63**	**4%**	

Additional Detail

Nuclear implemented a temporary hiring freeze in 2020 to manage costs through attrition and prior staffing reductions. However, hiring began again in 2021 as the reduced staffing levels were not sustainable for the long term.

RRE re-allocated budget funds to DEC in accordance with their processes of managing the business at a functional level. RRE did see some delays in outages from the spring to the fall due to COVID; however, these delays did not impact the total DEP 2020 outage schedule or spend.

Transmission did not cut any of its base or scheduled maintenance in 2020. However, it did reduce its budget in 2020 for non-routine maintenance which would have been used to address emerging or opportunistic items. Additionally, Transmission saw reductions in capital spend which resulted in reduced project O&M.

Delivery reduced capital spend in 2020 and, as a result, saw reduced project O&M. Additionally, Delivery saw underspend on communication and technology projects.

Corporate implemented a hiring freeze in 2020 to manage costs through attrition and prior staffing reductions. However, hiring began again in 2021 as the reduced staffing levels were not sustainable for the long term.

Duke Energy Progress
Docket No. E-2, Sub 1300
Public Staff Data Request No. 155
Date Sent: January 27, 2023
Date Requested: February 6, 2023

Public Staff Technical Contact: **Dustin Metz**
Phone #: (919) 733-1513
Email: dustin.metz@psncuc.nc.gov

Public Staff Legal Contact: **Robert Josey**
Phone #: (919) 733-0976
Email: robert.josey@psncuc.nc.gov

Topic: MYRP Project Loading and Staffing

Please provide any available responses electronically in a searchable native electronic format. If in Excel format, be sure to include all working formulas. In addition, please include (1) the name and title of the individual who has the responsibility for the subject matter addressed therein, and (2) the identity of the person making the response by name, occupation, and job title.

Note:

The following discovery is focused on the Company's required staffing levels and other key metrics to evaluate the proposed completion dates of the MYRP by Rate Year.

Key assumptions and labor units are respective to the general category listed above the section of itemized business units and work grouping.

If the Company is pooling distribution and transmission crews for purposes of metric reporting and assumptions, please so identify in the response.

Transmission and Transmission Substation Work

1. Please identify key staffing and labor metrics the Company typically uses to evaluate work projects, work project completion, and timeline management.

2. For Rate Years 1 through 3, list each of the Company's key staffing and labor metrics, for each Rate Year, along with the respective scores/requirements of each.

   a. If the Company did not perform such an analysis, please explain why not.

3. For Rate Years 1 through 3, please provide the following information per Rate Year as deemed necessary to complete all the Company's proposed work:

   a. Total hours of DEP employee craft and equivalent full-time employees.

b. Total number of DEP trucks.

c. List of specialized equipment/vehicles.

d. Total hours of external vendor employee craft and equivalent full-time employees.

e. Total number of external vendor trucks.

f. Total hours of DEP project management and equivalent full-time employees.

g. Total hours of vendor project management and equivalent full-time employees.

h. Total hours of DEP engineers and equivalent full-time employees.

i. Total hours of vendor engineers and equivalent full-time employees.

j. Total aggregate hours for all work and equivalent full-time employees:

   i. DEP employees

   ii. Vendors

k. List DEC resources used in the staffing and the equivalent full-time employees.

   i. If other DEP affiliate resources are required or expected to be utilized, please list those as well by affiliate.

4. For equipment that either (1) takes 6 months or longer to procure and deliver or (2) is a single piece of equipment that is >$150k, identify the total amount of equipment and labor costs by Rate Year.

5. For equipment that either (1) takes 9 months or longer to procure and deliver or (2) is a single piece of equipment that is >$300k, identify the total amount of equipment costs and labor by Rate Year.

   a. For Rate Year 1, has all the equipment (material cost) been ordered?

6. For equipment that either (1) takes 12 months or longer to procure and deliver or (2) is a single piece of equipment that is >$300k, identify the total amount of equipment costs and labor by Rate Year.

   a. For Rate Year 1, has all the equipment (material cost) been ordered?

7. For equipment that either (1) takes 18 months or longer to procure and deliver or (2) is a single piece of equipment that is >$300k, identify the total amount of equipment costs and labor by Rate Year.

    a. For Rate Year 1, has all the equipment (material cost) been ordered?

    b. For Rate Year 2, has all the equipment (material cost) been ordered?

8. Provide a list of all equipment by MYRP project that will take 24 months or longer to procure and deliver.

    a. For each project, list the date it was ordered or expects to be ordered.

9. For the last 5 years, list annually the number of DEP craft the Company has employed.

    a. List the total hours and equivalent full-time employees of DEP craft that have completed work toward construction-like projects, similar to the work scope in the MYRP (not including storm restoration activities or typical O&M-like work).

10. For the last 5 years, list annually the number of vendor craft the Company has contracted out.

    a. List the total hours and equivalent full-time employees of vendor craft that have completed work toward construction-like projects, similar to the work scope in the MYRP (not including storm restoration activities or typical O&M-like work).

11. For the last 5 years, list annually the key metrics the Company used to plan and prioritize work projects.

    a. Provide a detailed summary and supporting work papers of how the Company used historic metrics and trends to propose MYRP projects and completion by Rate Year.

12. Does the Company have enough internal resources to complete the MYRP proposed work for Rate Years 1 through 3?

    a. If so, please provide the analysis used to make such a determination.

    b. If so, please provide a detailed narrative of what future assumptions the Company used in staffing and quantify that to a percentage of increase of existing staffing and equivalent full-time employees.

    c. If not, please provide a narrative and analysis used to make such a determination.

d. If not, list which Rate Years the Company has identified internal staffing and workload related issues.

e. If not, provide a detailed narrative and assumptions of external labor (vendor or affiliate) resources the Company needs to supplement their internal labor resources.

i. List the total amount of work expected to be completed by internal versus external resources.

i. Identify each external source of labor to the extent known.

13. By Rate Year, list the amount of overtime assumed to meet project schedules.
    a. List internal labor amounts of OT assumed.
    b. List external and affiliate labor amounts of OT assumed.

14. By Rate Year, list the Company's expected percentage of completion of each MYRP project and their respective costs.

    a. Provide supporting analysis.

    b. List the number of projects and project costs that are assumed to have greater than 90% certainty of being completed in the respective rate year.

    c. List the number of projects and project costs that are assumed to have 81% to 90% certainty of being completed in the respective rate year.

    d. List the number of projects and project costs that are assumed to have 71% to 80% certainty of being completed in the respective rate year.

    e. List the number of projects and project costs that are assumed to have 70% or less certainty of being completed in the respective rate year.

15. For each MYRP project, please indicate whether it has dependencies on other MYRP projects in prior rate years (e.g., if there is a Rate Year 2 Substation and Line project that is dependent upon a Rate Year 1 Substation and Line project's completion, identify and describe each dependency).

16. For calendar years 2019, 2020, 2021, and 2022, please provide the following information for each year:
    a. Total number of internal FTEs assigned to transmission projects.
    b. Total number of external FTEs assigned to transmission projects.
    c. Total number of internal labor hours charged to transmission projects.
    d. Total number of external labor hours charged to transmission projects.

17. For calendar years 2023, 2024, 2025, and 2026, please provide the following information for each year for MYRP and non-MYRP related work that is currently planned or expected:
    a. Total number of internal FTEs assigned to transmission projects.
    b. Total number of external FTEs assigned to transmission projects.
    c. Total number of internal labor hours charged to transmission projects.
    d. Total number of external labor hours charged to transmission projects.

<u>Distribution and Distribution Substation Work</u>

18. Please identify key staffing and labor metrics the Company typically uses to evaluate work projects, work project completion, and timeline management.

19. For Rate Years 1 through 3, list each of the Company's key staffing and labor metrics along with the respective scores/requirements of each.

    a. If the Company did not perform such an analysis, please explain why not.

20. For Rate Years 1 through 3, please provide the following information per Rate Year as deemed necessary to complete all the Company's proposed work, and reference any supporting documents. Please also reconcile these responses with the labor hour estimates contained in the "Grid Plan vShare" document provided in response to PS DR 62-1 for Substation and Line projects.

    a. Total hours of DEP employee craft and equivalent full-time employees.

    b. Total number of DEP trucks.

    c. List of specialized equipment/vehicles.

    d. Total hours of external vendor employee craft and equivalent full-time employees.

    e. Total number of external vendor trucks.

    f. Total hours of DEP project management and equivalent full-time employees.

    g. Total hours of vendor project management and equivalent full-time employees.

    h. Total hours of DEP engineers and equivalent full-time employees.

    i. Total hours of vendor engineers and equivalent full-time employees.

    j. Total aggregate hours for all work and equivalent full-time employees:

        i. DEP employees

ii. Vendors

k. List DEC resources used in the staffing and the equivalent full-time employees.

i. If other DEP affiliate resources are required or expected to be utilized, please list those as well by affiliate.

21. For equipment that either (1) takes 6 months or longer to procure and deliver or (2) is a single piece of equipment that is >$100k, identify the total amount of equipment costs and labor by Rate Year.

22. For equipment that either (1) takes 9 months or longer to procure and deliver or (2) is a single piece of equipment that is >$300k, identify the total amount of equipment costs and labor by Rate Year.

a. For Rate Year 1, has all the equipment (material cost) been ordered?

23. For equipment that either (1) takes 12 months or longer to procure and deliver or (2) is a single piece of equipment that is >$200k, identify the total amount of equipment costs and labor by Rate Year.

a. For Rate Year 1, has all the equipment (material cost) been ordered?

24. For equipment that either (1) takes 18 months or longer to procure and deliver or (2) is a single piece of equipment that is >$200k, identify the total amount of equipment costs and labor by Rate Year.

a. For Rate Year 1, has all the equipment (material cost) been ordered?

b. For Rate Year 2, has all the equipment (material cost) been ordered?

25. Provide a list of equipment by MYRP project that will take 24 months or longer to procure and deliver.

a. For each project, list the date it was ordered or expects to be ordered.

26. For the last 5 years, list annually the number of DEP distribution craft the Company has employed.

a. List the total hours and equivalent full-time employees of DEP craft that have completed work toward construction-like projects, similar to the work scope in the MYRP (not including storm restoration activities or typical O&M-like work).

27. For the last 5 years, list annually the number of vendor craft the Company has contracted out.

a. List the total hours and equivalent full-time employees of vendor craft that have completed work toward construction-like projects, similar to the work scope in the MYRP (not including storm restoration activities or typical O&M-like work).

28. For the last 5 years, list annually key metrics the Company used to plan and prioritize work projects.

a. Provide a detailed summary and supporting work papers of how the Company used historic metrics and trends to propose MYRP projects and completion by Rate Year.

29. Does the Company have enough internal resources to complete the MYRP proposed work for Rate Years 1 through 3?

a. If so, please provide the analysis used to make such a determination.

b. If so, please provide a detailed narrative of what future assumptions the Company used in staffing and quantify that to a percentage of increase of existing staffing and equivalent full-time employees.

c. If not, please provide a narrative and analysis used to make such a determination.

d. If not, list which Rate Years the Company has identified internal staffing and workload related issues.

e. If not, provide a detailed narrative and assumptions of external labor (vendor or affiliate) resources the Company needs to supplement their internal labor resources.

i. List the total amount of work expected to be completed by internal versus external resources.

i. Identify each external source of labor to the extent known.

30. By Rate Year, list the amount of overtime assumed to meet project schedules.
a. List internal labor amounts of OT assumed.
b. List external labor amounts of OT assumed.

31. By Rate Year, list the Company's expected percentage of completion of each MYRP project and their respective costs.

a. Provide supporting analysis.

b. List the number of projects and project costs that are assumed to have greater than 90% certainty of being completed in the respective rate year.

c. List the number of projects and project costs that are assumed to have 81% to 90% certainty of being completed in the respective rate year.

d. List the number of projects and project costs that are assumed to have 71% to 80% certainty of being completed in the respective rate year.

e. List the number of projects and project costs that are assumed to have 70% or less certainty of being completed in the respective rate year.

32. For each MYRP project, please indicate whether it has dependencies on other MYRP projects in prior rate years (e.g., if there is a Rate Year 2 Substation and Line project that is dependent upon a Rate Year 1 Substation and Line project's completion, describe the dependency).

33. For calendar years 2019, 2020, 2021, and 2022, please provide the following information for each year:
a. Total number of internal FTEs assigned to distribution projects.
b. Total number of external FTEs assigned to distribution projects.
c. Total number of internal labor hours charged to distribution projects.
d. Total number of external labor hours charged to distribution projects.

34. For calendar years 2023, 2024, 2025, and 2026, please provide the following information for each year for MYRP and non-MYRP related work that is currently planned or expected:
a. Total number of internal FTEs assigned to distribution projects.
b. Total number of external FTEs assigned to distribution projects.
c. Total number of internal labor hours charged to distribution projects.
d. Total number of external labor hours charged to distribution projects.

Nuclear Work

35. Please identify key staffing and labor metrics the Company typically uses to evaluate work projects, work project completion, and timeline management.

36. For Rate Years 1 through 3, list each of the Company's key staffing and labor metrics along with the respective scores/requirements of each.

a. If the Company did not perform such an analysis, please explain why not.

37. Describe whether the Company's view of Nuclear-related work for capital projects relies more on external vendor support and/or delivery schedules than the work required for reconducting a line or designing and building a new substation.

Note: the intent of the question is to have the Company explain the discrete differences among business units and how some business units may rely more on external vendors given the unique project and/or skill sets.

38. For Rate Years 1 through 3, please provide the following per Rate Year as deemed necessary to complete all the Company's proposed work:

    a. Total hours of DEP employees and equivalent full-time employees

    b. Total hours of external vendor employees and equivalent full-time employees.

    c. Total hours of DEP project management and equivalent full-time employees

    d. Total hours of vendor project management and equivalent full-time employees

    e. Total hours of DEP engineers and equivalent full-time employees.

    f. Total hours of vendor engineers and equivalent full-time employees.

    g. Total aggregate hours for all work and equivalent full-time employees:

        i. DEP employees

        ii. Vendors

    h. List all DEC resources used in the staffing and the equivalent full-time employees.

39. For equipment that either takes 6 months or longer to procure and deliver or for a single piece of equipment that is >$200k, identify the total amount of equipment costs and labor by Rate Year.

40. For equipment that either takes 9 months or longer to procure and deliver or for a single piece of equipment that is >$200k, identify the total amount of equipment costs and labor by Rate Year.

    a. For Rate Year 1, has all the equipment (material cost) been ordered?

41. For equipment that either takes 12 months or longer to procure and deliver or for a single piece of equipment that is >$200k, identify the total amount of equipment costs and labor by Rate Year.

    a. For Rate Year 1, has all the equipment (material cost) been ordered?

42. For equipment that either takes 18 months or longer to procure and deliver or for a single piece of equipment that is >$200k, identify the total amount of equipment and labor costs by Rate Year.

    a. For Rate Year 1, has all the equipment (material cost) been ordered?

    b. For Rate Year 2, has all the equipment (material cost) been ordered?

43. Provide a list of all equipment by MYRP project that will take 24 months or longer to procure and deliver.

    a. For each project, list the date it was ordered or expects to be ordered.

44. For the last 5 years, list annually the number of DEP staff used for nuclear related work the Company has employed.

    a. List the total hours and equivalent full-time employees of DEP staff that have completed work toward construction-like projects, similar to the work scope in the MYRP (not including typical O&M-like work).

45. For the last 5 years, list annually the number of vendor craft the Company has contracted out.

    a. List the total hours and equivalent full-time employees of vendor craft that have completed work toward construction-like projects, similar to the work scope in the MYRP (not including typical O&M-like work).

46. For the last 5 years, list annually key metrics the Company would use to plan and prioritize work projects.

    a. Provide a detailed summary and supporting work papers of how the Company used historic metrics and trends to propose MYRP projects and completion by Rate Year.

47. Does the Company have enough internal resources to complete the MYRP proposed work for Rate Years 1 through 3.

    a. If so, please provide the analysis used to make such a determination.

    b. If so, please provide a detailed narrative of what future assumptions the Company used in staffing and quantify that to a percentage of increase of existing staffing and equivalent full-time employees.

    c. If not, please provide a narrative and analysis used to make such a determination.

    d. If not, list which Rate Years the Company has identified internal staffing and workload related issues.

    e. If not, provide a detailed narrative and assumptions of external labor (vendor or DEC) resources the Company needs to supplement their internal labor resources.

        i. List the total amount of work expected to be completed by internal versus external resources.

i. Identify each external source of labor to the extent known.

48. By Rate Year, list the amount of overtime assumed to meet project schedules.
   a. List internal labor amounts of OT assumed.
   b. List external labor amounts of OT assumed.

49. By Rate Year, list the Company's expected percentage of completion of each MYRP project and their respective costs.

   a. Provide supporting analysis.

   b. List the number of projects and project costs that are assumed to have greater than 90% certainty of being completed in the respective rate year.

   c. List the number of projects and project costs that are assumed to have 81% to 90% certainty of being completed in the respective rate year.

   d. List the number of projects and project costs that are assumed to have 71% to 80% certainty of being completed in the respective rate year.

   e. List the number of projects and project costs that are assumed to have 70% or less certainty of being completed in the respective rate year.

50. For each MYRP project, please indicate whether it has dependencies on other MYRP projects in prior rate years (e.g., if there is a Rate Year 2 I&C project that is dependent upon a Rate Year 1 equipment installation completion, describe the dependency).

51. For each MYRP project in Rate Years 1 through 3, answering the following:

   a. Is the project already underway?

   b. Total percentage of work already completed.

   c. Is the work already under contract and/or is there an executed purchase order with a vendor?

      i. Does the vendor schedule align with the Company's proposed MYRP schedule?

   d. Is installation and commissioning of the project already included in the proposed outage plans?

   e. Has the project been identified on critical path?

      i. If the project has been identified on critical path, list the number of days on critical path.

ii. If the project has not been identified on critical path, is this because the project is proposed to have no issues, or is it that an outage plan has not been created and therefore there is no critical path?

f. If the Commission does not approve the MYRP, will the Company continue with the proposed project(s) in each respective Rate Year?
   i. If not, why not?

52. For calendar years 2019, 2020, 2021, and 2022, please provide the following information for each year:
   a. Total number of internal FTEs assigned to nuclear projects.
   b. Total number of external FTEs assigned to nuclear projects.
   c. Total number of internal labor hours charged to nuclear projects.
   d. Total number of external labor hours charged to nuclear projects.

53. For calendar years 2023, 2024, 2025, and 2026, please provide the following information for each year for MYRP and non-MYRP related work that is currently planned or expected:
   a. Total number of internal FTEs assigned to nuclear projects.
   b. Total number of external FTEs assigned to nuclear projects.
   c. Total number of internal labor hours charged to nuclear projects.
   d. Total number of external labor hours charged to nuclear projects.

<u>General Questions to all business classes or business jurisdictions:</u>

54. Provide a general narrative of any additional factors, items, metrics, scoring, or other items the Company considered to be legitimate constraints on project management, project planning, and resource loading, and how each is reflected in the proposed MYRP by Rate Year.

55. For calendar years 2019, 2020, 2021, and 2022, please provide the following information for each year:
   a. Total number of internal FTEs assigned to all projects and typical work.
   b. Total number of external FTEs assigned to all projects and typical work.
   c. Total number of internal labor hours charged to all projects and typical work.
   d. Total number of external labor hours charged to all projects and typical work.

56. For calendar years 2023, 2024, 2025, and 2026, please provide the following information for each year for MYRP and non-MYRP related work that is currently planned or expected:
   a. Total number of internal FTEs assigned to all projects and typical work.
   b. Total number of external FTEs assigned to all projects and typical work.
   c. Total number of internal labor hours charged to all projects and typical work.

d. Total number of external labor hours charged to all projects and typical work.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-1, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-1
Page 1 of 1

Request:

1. Please identify key staffing and labor metrics the Company typically uses to evaluate work projects, work project completion, and timeline management.

Response:

The Transmission function evaluates resourcing strategies on an ongoing basis as work progresses and employs strategies like shifting resources to areas of need and flexing work schedules. For Project Management and Engineering, resources are identified and assigned on a project-by-project basis. When internal resources are not available to meet the time constraints of the project, external resources are identified. Likewise, for the construction phase of the projects, internal construction resources are assigned when they are available and external suppliers are utilized to supplement those resources as needed. More specifically, during project development, resource forecasting (largely for craft/line labor) is performed by taking into consideration the identified work scopes, estimated durations and operational considerations to determine the number of crew resources needed to execute the plan. The resulting resource forecast is compared to current headcount to determine what supplemental external labor is needed to support the forecasted resource need.

Concerning "timeline management," a practice the Transmission function utilizes at the conceptual design stage is reserving/ordering certain materials from suppliers (i.e., breakers, transformers, regulators, relay panels, control houses) in the Company's internal work management systems. In some cases, the Company can reserve manufacturing "slots" with suppliers for project components. Other materials are ordered during the detailed design stage, or reserved from the Company's inventory.

Further, the transmission function creates a more detailed "look ahead" workplan at 6-month intervals that considers outage constraints, summer and winter peaks, and generation outages.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-2, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-2
Page 1 of 1

Request:

2. For Rate Years 1 through 3, list each of the Company's key staffing and labor metrics, for each Rate Year, along with the respective scores/requirements of each.
   a. If the Company did not perform such an analysis, please explain why not.

Response:

Please refer to the Company's response to PSDR 155-1. The Company has not performed the analysis requested in PSDR 155-2 due to the nature of the varying types of projects, resource needs, and operational conditions impacting timing of construction; but, for the reasons explained in the response to PSDR 155-1 and throughout these responses, is confident that the projects proposed for each Rate Year will be completed.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-3, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-3
Page 1 of 1

Request:

3. For Rate Years 1 through 3, please provide the following information per Rate Year as deemed necessary to complete all the Company's proposed work:
    a. Total hours of DEP employee craft and equivalent full-time employees.
    b. Total number of DEP trucks.
    c. List of specialized equipment/vehicles.
    d. Total hours of external vendor employee craft and equivalent full-time employees.
    e. Total number of external vendor trucks.
    f. Total hours of DEP project management and equivalent full-time employees.
    g. Total hours of vendor project management and equivalent full-time employees.
    h. Total hours of DEP engineers and equivalent full-time employees.
    i. Total hours of vendor engineers and equivalent full-time employees.
    j. Total aggregate hours for all work and equivalent full-time employees:
        i. DEP employees
        ii. Vendors
    k. List DEC resources used in the staffing and the equivalent full-time employees.
        i. If other DEP affiliate resources are required or expected to be utilized, please list those as well by affiliate.

Response:

Please refer to the Company's response to PSDR 155-1.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-4, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-4
Page 1 of 1

Request:

4. For equipment that either (1) takes 6 months or longer to procure and deliver or (2) is a single piece of equipment that is >$150k, identify the total amount of equipment and labor costs by Rate Year.

Response:

Please refer to DEP's response to PSDR 155-1. The dynamic nature of the procurement and project development processes utilized by DEP (which is described in response to PSDR 155-1) renders this data request premature since final costs for individual pieces of equipment and the procurement timelines are not certain until equipment is actually ordered – which has not occurred in the vast majority of cases with regard to MYRP projects in DEP's MYRP.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-5, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-5
Page 1 of 1

Request:

5. For equipment that either (1) takes 9 months or longer to procure and deliver or (2) is a single piece of equipment that is >$300k, identify the total amount of equipment costs and labor by Rate Year.
   a. For Rate Year 1, has all the equipment (material cost) been ordered?

Response:

Please see DEP's responses to PSDR 155-1 and 155-4.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-6, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-6
Page 1 of 1

Request:

6. For equipment that either (1) takes 12 months or longer to procure and deliver or (2) is a single piece of equipment that is >$300k, identify the total amount of equipment costs and labor by Rate Year.
   a. For Rate Year 1, has all the equipment (material cost) been ordered?

Response:

Please see DEP's responses to PSDR 155-1 and 155-4.

**Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155**

Docket No. E-2, Sub 1300

**Date of Request: January 27, 2023
Date of Response: February 15, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-7, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-7
Page 1 of 1

Request:

7. For equipment that either (1) takes 18 months or longer to procure and deliver or (2) is a single piece of equipment that is >$300k, identify the total amount of equipment costs and labor by Rate Year.
   a. For Rate Year 1, has all the equipment (material cost) been ordered?
   b. For Rate Year 2, has all the equipment (material cost) been ordered?

Response:

Please see DEP's responses to PSDR 155-1 and 155-4.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-8, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-8
Page 1 of 1

Request:

8. Provide a list of all equipment by MYRP project that will take 24 months or longer to procure and deliver.
    a. For each project, list the date it was ordered or expects to be ordered.

Response:

Please see DEP's responses to PSDR 155-1 and 155-4.

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-9 and 155-16
Page 1 of 1

Hours	**2018**	**2019**	**2020**	**2021**	**2022**	Data Request
Craft	186,567	261,055	282,913	270,923	259,737	PSDR #155-9
Total	245,007	342,457	381,099	358,785	344,748	PSDR #155-16

*FTEs**	**2018**	**2019**	**2020**	**2021**	**2022**	
Craft	112	157	170	163	156	PSDR #155-9
Total	147	206	229	216	207	PSDR #155-16

**Full time equivalent based on productive hours worked in a calendar year.*

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-9, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-9
Page 1 of 1

Request:

9. For the last 5 years, list annually the number of DEP craft the Company has employed.
   a. List the total hours and equivalent full-time employees of DEP craft that have completed work toward construction-like projects, similar to the work scope in the MYRP (not including storm restoration activities or typical O&M-like work).

Response:

Please see "PSDR 155-9_155-16 Attachment.xlsx".

**Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155**

Docket No. E-2, Sub 1300

**Date of Request: January 27, 2023
Date of Response: February 15, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-10, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-10
Page 1 of 1

Request:

10. For the last 5 years, list annually the number of vendor craft the Company has contracted out.
    a. List the total hours and equivalent full-time employees of vendor craft that have completed work toward construction-like projects, similar to the work scope in the MYRP (not including storm restoration activities or typical O&M-like work).

Response:

Hours and headcount are not tracked for Transmission vendor craft resources. These resources are typically managed with Not To Exceed ("NTE") contracts.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-11, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-11
Page 1 of 1

Request:

11. For the last 5 years, list annually the key metrics the Company used to plan and prioritize work projects.
    a. Provide a detailed summary and supporting work papers of how the Company used historic metrics and trends to propose MYRP projects and completion by Rate Year.

Response:

As explained in DEP PS DR 75-1 and DEP PS DR 75-2, Subject Matter Experts (SMEs) from Transmission Asset Management and Transmission Planning identify and sponsor project work based on a variety of inputs. Transmission uses reliability metrics of SAIDI (Outage duration) and OHMY-SA (Outage frequency) as inputs that shape capital investment needs. Other considerations are public safety, environmental threats, security risk, financial risk, etc. Beginning in 2019, the Company began using Copperleaf Product Suite to qualitatively evaluate each project's scope to help inform capital investment decisions, develop a Cost Benefit Analysis, and aid with project prioritization. These SMEs, in conjunction with the Project Management Team, Asset Management, Planning, Work Management, Outage Coordinators and Engineering are ultimately responsible for prioritizing all projects that are proposed in the overall Transmission investment plan.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-12, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-12
Page 1 of 1

Request:

12. Does the Company have enough internal resources to complete the MYRP proposed work for Rate Years 1 through 3?
    a. If so, please provide the analysis used to make such a determination.
    b. If so, please provide a detailed narrative of what future assumptions the Company used in staffing and quantify that to a percentage of increase of existing staffing and equivalent full-time employees.
    c. If not, please provide a narrative and analysis used to make such a determination.
    d. If not, list which Rate Years the Company has identified internal staffing and workload related issues.
    e. If not, provide a detailed narrative and assumptions of external labor (vendor or affiliate) resources the Company needs to supplement their internal labor resources.
        i. List the total amount of work expected to be completed by internal versus external resources.
            1. Identify each external source of labor to the extent known.

Response:

12. No, the Company does not have enough internal resources to complete the MYRP proposed work for Rate Years 1 through 3 but, consistent with past practice, will continue to rely on external resources where needed in order to complete the work as explained further below.

a. -b. N/A

c. Please refer to the Company's response to PSDR 155-1. The transmission function's business model is to maintain a complement of full-time employees and contingent workers, and then supplement labor, when necessary, with external vendor resources. This model allows the Company to ramp up or down as needed. Note that most of the Company's construction/craft labor is external vendors due to the seasonal nature of construction activities. The Company maintains partnerships with strategic alliance contractors and thus has confidence that they will be available when needed.

d. At this time, the Company has not identified any internal staffing and workload related issues.

e. If internal crews are maxed out, then the Company will follow its typical practice and rely on Master Service Agreement (MSA) labor for the bulk of construction activities. These crews are typically local and can do both responsive and planned work. If a labor constraint exists, the Company takes specific projects to market for non-contracted (non-MSA) suppliers to bid on. We intend to bid our MSA work in Q3 2023 and will award agreements based on forecasted need for 3-5 year work plans.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-13, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-13
Page 1 of 1

Request:

13. By Rate Year, list the amount of overtime assumed to meet project schedules.
    a. List internal labor amounts of OT assumed.
    b. List external and affiliate labor amounts of OT assumed.

Response:

The Company does not assume overtime in project planning.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-14, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-14
Page 1 of 1

Request:

14. By Rate Year, list the Company's expected percentage of completion of each MYRP project and their respective costs.
    a. Provide supporting analysis.
    b. List the number of projects and project costs that are assumed to have greater than 90% certainty of being completed in the respective rate year.
    c. List the number of projects and project costs that are assumed to have 81% to 90% certainty of being completed in the respective rate year.
    d. List the number of projects and project costs that are assumed to have 71% to 80% certainty of being completed in the respective rate year.
    e. List the number of projects and project costs that are assumed to have 70% or less certainty of being completed in the respective rate year.

Response:

Please see DEP's responses to PSDR 155-1 and 155-4.

The Company is confident that the projects within each Rate Year can be completed. However, the Company further observes that the Commission itself has acknowledged the need for the Company to exercise discretion in implementing the MYRP in order to benefit customers. Therefore, it is likely that a variety of factors (including factors outside of the control of the Company) will require the Company to modify or adjust certain MYRP projects for the benefit for customers. Please refer to "Maley Direct Exhibit 2 - MYRP Distribution Project Detail" for the estimated cost and project completion date for transmission projects included in DEP's MYRP.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-15, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-15
Page 1 of 1

Request:

15. For each MYRP project, please indicate whether it has dependencies on other MYRP projects in prior rate years (e.g., if there is a Rate Year 2 Substation and Line project that is dependent upon a Rate Year 1 Substation and Line project's completion, identify and describe each dependency).

Response:

At this time, DEP has not identified any MYRP projects that have dependencies between rate years. The primary driver for these dependencies occurs in geographical areas which are sensitive to multiple line clearances at the same time. As work plans are created and continue to mature, clearance requirements will be evaluated at the portfolio level. Work plans will be adjusted accordingly to minimize the number of dependencies between projects.

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-9 and 155-16
Page 1 of 1

Hours	**2018**	**2019**	**2020**	**2021**	**2022**	Data Request
Craft	186,567	261,055	282,913	270,923	259,737	PSDR #155-9
Total	245,007	342,457	381,099	358,785	344,748	PSDR #155-16

*FTEs**	**2018**	**2019**	**2020**	**2021**	**2022**	
Craft	112	157	170	163	156	PSDR #155-9
Total	147	206	229	216	207	PSDR #155-16

**Full time equivalent based on productive hours worked in a calendar year.*

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-16, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-16
Page 1 of 1

Request:

16. For calendar years 2019, 2020, 2021, and 2022, please provide the following information for each year:
    a. Total number of internal FTEs assigned to transmission projects.
    b. Total number of external FTEs assigned to transmission projects.
    c. Total number of internal labor hours charged to transmission projects.
    d. Total number of external labor hours charged to transmission projects.

Response:

a. & c. Please see "PSDR 155-9_155-16 Attachment.xlsx".
b. & d. Please see DEP's response to PSDR 155-10.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-17, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-17
Page 1 of 1

Request:

17. For calendar years 2023, 2024, 2025, and 2026, please provide the following information for each year for MYRP and non-MYRP related work that is currently planned or expected:
    a. Total number of internal FTEs assigned to transmission projects.
    b. Total number of external FTEs assigned to transmission projects.
    c. Total number of internal labor hours charged to transmission projects.
    d. Total number of external labor hours charged to transmission projects.

Response:

Please see the Company's responses to PSDR 155-1 and 155-2. As previously noted, for the Transmission function, resource forecasting (specifically craft/line labor) is performed based upon work plans/projects. The Company does, however, have a base complement of internal resources supporting MYRP and non-MYRP work for normal business functions.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-18, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-18
Page 1 of 2

Request:

18. Please identify key staffing and labor metrics the Company typically uses to evaluate work projects, work project completion, and timeline management.

Response:

The Distribution function is confident in its ability to execute the Distribution projects within the MYRP as the Company has been doing these types of projects for years and thus, is experienced in executing this type of work. The Company employs multiple strategies to ensure the resources needed are secured in a timely manner. The resource forecast is evaluated against current resources, company and contractor, and any gaps are identified. Upon completion of the resource demand plan and gap analysis, contracting strategy options are evaluated to fulfill any outstanding resource needs.

Examples of these strategies include, but are not limited to, contracts for Distribution Line Construction, Enterprise Engineering of Choice contracts (EEOC), contracts for specific workstreams (i.e., Pole Inspection, Flagging, Locates, Damage Assessment, etc.), Engineering turnkey contracts (EPC), and Regional and Niche contracts for Distribution Line and Engineer/Construct contracts. The Company also evaluates resourcing strategies on an ongoing basis as work progresses and employs strategies like shifting resources to areas of need and flexing work schedules to ensure adequate resources are available.

Specific to the Distribution function, resource forecasting (specifically craft/line labor) is performed annually in total for the Carolinas for all Distribution work scopes/projects. The most recent resource forecasting was performed for 2023. The resource forecasting methodology takes the planned/estimated spend and uses a historical spend per line resource metric to determine the number of resources needed to execute the planned/estimated amount of spend for the distribution function. The resulting resource forecast is compared to current headcount to determine what actions if any are needed to support the forecasted resource need.

For labor, CAPEX (not Plant In-Service) during the MYRP years is the main metric to forecast resources required to execute distribution work. CAPEX has plateaued in 2023 and is relatively smooth through the MYRP years. Leading up to 2023 (during 2020-2022), the Company acquired the level of resources needed to meet 2023 CAPEX spend. The Company leverages multiyear MSAs with both our craft and engineering vendors. The distribution function maintains MSAs with three different types of craft vendors: large strategic alliance partners, smaller regional/niche partners, and EpC partners. For engineering, our MSAs are with Enterprise Engineering of Choice (EEoC) partners.

For materials, recognizing supply chain constraints, the Company previously initiated, and still maintains, a partial-activation of our Incident Command Structure to focus on successfully navigating/mitigating these constraints. Some specific strategies and actions Supply Chain has taken and continues to exercise are: advanced material purchases (rather than waiting for demand signals in our work management system); securing advanced manufacturing slots/capacity; leveraging off-shore suppliers; and coordinating with Distribution Standards to develop and approve alternate material specifications to open opportunities for additional on-shore and off-shore suppliers and their products.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-19, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-19
Page 1 of 1

Request:

19. For Rate Years 1 through 3, list each of the Company's key staffing and labor metrics along with the respective scores/requirements of each.
    a. If the Company did not perform such an analysis, please explain why not.

Response:

Please see DEP's responses to PSDR 155-1 and 155-18. The Company has not performed the analysis requested in PSDR 155-2 for all three rate years. However, the Company has performed resource forecasting for the 2023 plan year and for the reasons explained in the response to PSDR 155-1 and 155-18 and throughout these responses, is confident that the projects proposed for each Rate Year will be completed.

a. The forecasted spend for the Distribution function for 2024 and beyond is expected to be relatively consistent with 2023. As such, the Company does not anticipate the need for a significant increase in craft/line resources beyond what is forecasted for 2023.

		Jan 2022
Actual Distribution Line Resourced Capital Spend		
Carolinas	Caro Zone Ops Central	19,887,316
Carolinas	Caro Ops Coastal Zone	9,710,419
Carolinas	Caro Zone Ops Mountains	11,739,633
Carolinas	Caro Ops Pee Dee Zone	10,739,292
Carolinas	Caro Zone Ops Triad	8,321,993
Carolinas	Caro Zone Ops Triangle North	10,460,272
Carolinas	Caro Zone Ops Triangle South	14,294,555
Carolinas	Caro Zone Ops Upstate	15,202,165
Carolinas	All Other	-
Carolinas	Total Spend	100,355,645
Total Distribution Line HC		
Carolinas	Caro Zone Ops Central	785
Carolinas	Caro Ops Coastal Zone	506
Carolinas	Caro Zone Ops Mountains	583
Carolinas	Caro Ops Pee Dee Zone	317
Carolinas	Caro Zone Ops Triad	496
Carolinas	Caro Zone Ops Triangle North	554
Carolinas	Caro Zone Ops Triangle South	595
Carolinas	Caro Zone Ops Upstate	579
Carolinas	All Other	-
Carolinas	Total Headcount	4,415
Estimated Annual Spend per HC		
Carolinas	Caro Zone Ops Central	304,010
Carolinas	Caro Ops Coastal Zone	230,287
Carolinas	Caro Zone Ops Mountains	241,639
Carolinas	Caro Ops Pee Dee Zone	406,535
Carolinas	Caro Zone Ops Triad	201,339
Carolinas	Caro Zone Ops Triangle North	226,576
Carolinas	Caro Zone Ops Triangle South	288,294
Carolinas	Caro Zone Ops Upstate	315,071
Carolinas	All Other	-
Carolinas	$ per HC - Month	**272,767**
Carolinas	$ per HC - YTD	272,767

Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022
25,078,812	27,660,652	23,658,876	24,402,621	34,179,964	23,774,711	36,929,969
14,269,332	18,510,505	15,247,246	17,334,437	21,329,156	17,651,686	19,821,338
14,221,000	21,618,466	20,114,942	17,508,222	24,231,362	21,916,627	19,920,597
8,577,529	13,573,454	12,490,676	11,397,501	11,765,919	11,780,476	12,482,645
13,774,055	19,125,920	18,763,887	15,694,353	20,019,508	14,285,641	15,149,849
17,893,859	19,582,471	18,881,182	18,532,396	22,255,800	19,390,163	22,693,234
19,288,881	26,639,298	17,972,882	20,164,935	26,229,232	26,712,136	21,892,147
18,613,551	22,380,030	21,129,222	23,375,137	22,447,055	19,536,457	24,322,675
-	-	-	-	-	-	-
131,717,018	169,090,795	148,258,912	148,409,602	182,457,995	155,047,897	173,212,454
802	793	815	820	849	914	890
538	542	538	554	638	627	630
579	602	655	652	662	672	653
325	327	310	315	333	353	346
517	521	532	556	562	561	538
581	594	604	616	593	607	652
564	598	632	642	665	671	659
601	619	616	633	644	641	644
-	-	-	-	-	-	-
4,507	4,596	4,702	4,788	4,946	5,046	5,012
375,244	418,572	348,352	357,112	483,109	312,141	497,932
318,275	409,827	340,087	375,475	401,175	337,831	377,549
294,736	430,933	368,518	322,237	439,239	391,368	366,075
316,709	498,108	483,510	434,191	423,997	400,469	432,924
319,707	440,520	423,246	338,727	427,463	305,575	337,915
369,581	395,605	375,123	361,021	450,370	383,331	417,667
410,402	534,568	341,257	376,915	473,309	477,713	398,643
371,652	433,862	411,608	443,131	418,268	365,737	453,218
-	-	-	-	-	-	-
350,700	**441,490**	**378,372**	**371,954**	**442,680**	**368,723**	**414,715**
312,135	356,115	361,859	363,960	377,888	376,486	381,527

Sep 2022	Oct 2022	Nov 2022	Dec 2022	YTD 2022
30,488,952	26,069,398	20,825,521	48,289,658	341,246,448
24,097,057	15,483,380	18,729,067	23,707,084	215,890,707
22,740,895	26,090,950	18,808,898	21,078,070	239,989,661
15,052,021	12,265,330	12,169,040	14,794,959	147,088,842
16,356,818	16,996,875	15,456,981	21,391,644	195,337,524
20,719,480	20,393,249	25,773,978	37,067,034	253,643,115
22,499,985	21,834,321	24,180,451	25,918,766	267,627,588
19,523,654	22,363,657	25,178,986	30,227,914	264,300,502
-	-	-	-	-
171,478,862	161,497,160	161,122,920	222,475,127	1,925,124,387
897	880	875	910	10,230
654	647	642	642	7,158
677	680	690	713	7,818
350	360	358	357	4,051
555	583	579	589	6,589
674	703	713	734	7,625
637	647	644	641	7,595
661	670	682	675	7,665
-	-	-	-	-
5,105	5,170	5,183	5,261	58,731
407,879	355,492	285,607	636,787	400,289
442,148	287,172	350,076	443,123	361,929
403,088	460,429	327,111	354,750	368,365
516,069	408,844	407,901	497,310	435,711
353,661	349,850	320,352	435,823	355,752
368,893	348,107	433,784	606,001	399,176
423,862	404,964	450,567	485,219	422,848
354,439	400,543	443,032	537,385	413,778
-	-	-	-	-
403,084	**374,848**	**373,042**	**507,451**	**393,344**
384,079	383,091	382,117	393,344	

Definitions:

Distribution Line Resourced Spend: For purposes of Distribution line resource forecasting, the total capital spend is segregated between the work scopes/projects our Distribution line resources (company or contractor) execute vs. the work scopes/projects they do not execute. The best example of Not Distribution Line Resourced is the work performed by our Transmission group related to T to D substations. Internally, Customer Delivery "funds" this work, but the work is executed by resources controlled by our Transmission group.

Annual $ per HC: This is a metric Duke began using for Distribution line resource forecasting in 2022. The calculation is simply Total Actual Capital Distribution Line Resourced Spend divided by the cumulative Distribution line resource headcount for the corresponding period. The resulting calculating is multiplied by 12 to determine the Annual $ per HC. In simple terms, the resulting calculation is reflective of the total amount of spend that was associated with each Distribution line resource.

Distribution Line Forecasting Methodology: As the 2023 budget was finalized, the Distribution Line Resourced component of the 2023 budget was determined. The total 2023 Distribution Line Resourced Budget is divided by the 2022 Annual $ per HC to estimate the total number of resources that will be needed to execute the budget amount.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1300
PS DR 155-20

Customer Delivery Carolinas - Capital (CapEx) - Distribution Line Resource Forecast

Zone	Spend Category	Dec'22 YTD Actual	2023 Budget	2023 vs. Dec'22 YTD Actual	2022 Annual $ per HC	2023 Estimated HC	Jan'23 Actual HC	Variance to Jan'23 HC
Central	Distribution Line Resourced Spend	341,246,448	358,212,463	16,966,015	400,289	895	930	35
Central	Not Distribution Line Resourced Spend	15,477,670	49,204,651	33,726,981				
	Zone Total	**356,724,118**	**407,417,114**	**50,692,996**				
Coastal	Distribution Line Resourced Spend	215,890,707	223,199,218	7,308,511	361,929	617	642	25
Coastal	Not Distribution Line Resourced Spend	20,863,891	25,898,925	5,035,034				
	Zone Total	**236,754,598**	**249,098,143**	**12,343,545**				
Mountains	Distribution Line Resourced Spend	239,989,661	274,995,648	35,005,987	368,365	747	708	(39)
Mountains	Not Distribution Line Resourced Spend	15,058,154	21,348,890	6,290,736				
	Zone Total	**255,047,814**	**296,344,537**	**41,296,723**				
PeeDee	Distribution Line Resourced Spend	147,088,842	159,768,264	12,679,422	435,711	367	355	(12)
PeeDee	Not Distribution Line Resourced Spend	13,620,948	21,677,841	8,056,892				
	Zone Total	**160,709,790**	**181,446,105**	**20,736,315**				
Triad	Distribution Line Resourced Spend	195,337,524	210,138,673	14,801,149	355,752	591	571	(20)
Triad	Not Distribution Line Resourced Spend	6,991,121	16,311,804	9,320,683				
	Zone Total	**202,328,645**	**226,450,477**	**24,121,832**				
Triangle North	Distribution Line Resourced Spend	253,643,115	291,631,000	37,987,885	399,176	731	759	28
Triangle North	Not Distribution Line Resourced Spend	24,040,525	14,033,944	(10,006,581)				
	Zone Total	**277,683,640**	**305,664,944**	**27,981,304**				
Triangle South	Distribution Line Resourced Spend	267,627,588	307,816,527	40,188,939	422,848	728	649	(79)
Triangle South	Not Distribution Line Resourced Spend	36,061,042	43,263,170	7,202,128				
	Zone Total	**303,688,629**	**351,079,697**	**47,391,068**				
Upstate	Distribution Line Resourced Spend	264,300,502	309,228,903	44,928,401	413,778	747	697	(50)
Upstate	Not Distribution Line Resourced Spend	13,531,715	42,569,062	29,037,347				
	Zone Total	**277,832,217**	**351,797,965**	**73,965,748**				
Region Other	Distribution Line Resourced Spend	-	-	-				
Region Other	Not Distribution Line Resourced Spend	47,529,702	43,618,519	(3,911,183)				
		47,529,702	**43,618,519**	**(3,911,183)**				
Carolinas Total	Distribution Line Resourced Spend	**1,925,124,387**	**2,134,990,696**	**209,866,309**		**5,423**	**5,311**	**(112)**
Carolinas Total	Not Distribution Line Resourced Spend	193,174,767	277,926,806	84,752,039				
		2,118,299,154	**2,412,917,502**	**294,618,348**				

Duke Energy Progress, LLC
Docket No. E-2, Sub 1300
PS DR 155-20

		Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	YTD 2022
Actual Distribution Line Resourced Capital Spend														
Carolinas	Caro Zone Ops Central	19,887,316	25,078,812	27,660,652	23,658,876	24,402,621	34,179,964	23,774,711	36,929,969	30,488,952	26,069,398	20,825,521	48,289,658	341,246,448
Carolinas	Caro Ops Coastal Zone	9,710,419	14,269,332	18,510,505	15,247,246	17,334,437	21,329,156	17,651,686	19,821,338	24,097,057	15,483,380	18,729,067	23,707,084	215,890,707
Carolinas	Caro Zone Ops Mountains	11,739,633	14,221,000	21,618,466	20,114,942	17,508,222	24,231,362	21,916,627	19,920,597	22,740,895	26,090,950	18,808,898	21,078,070	239,989,661
Carolinas	Caro Ops Pee Dee Zone	10,739,292	8,577,529	13,573,454	12,490,676	11,397,501	11,765,919	11,780,476	12,482,645	15,052,021	12,265,330	12,169,040	14,794,959	147,088,842
Carolinas	Caro Zone Ops Triad	8,321,993	13,774,055	19,125,920	18,763,887	15,694,353	20,019,508	14,285,641	15,149,849	16,356,818	16,996,875	15,456,981	21,391,644	195,337,524
Carolinas	Caro Zone Ops Triangle North	10,460,272	17,893,859	19,582,471	18,881,182	18,532,396	22,255,800	19,390,163	22,693,234	20,719,480	20,393,249	25,773,978	37,067,034	253,643,115
Carolinas	Caro Zone Ops Triangle South	14,294,555	19,288,881	26,639,298	17,972,882	20,164,935	26,229,232	26,712,136	21,892,147	22,499,985	21,834,321	24,180,451	25,918,766	267,627,588
Carolinas	Caro Zone Ops Upstate	15,202,165	18,613,551	22,380,030	21,129,222	23,375,137	22,447,055	19,536,457	24,322,675	19,523,654	22,363,657	25,178,986	30,227,914	264,300,502
Carolinas	All Other	-	-	-	-	-	-	-	-	-	-	-	-	-
Carolinas	Total Spend	100,355,645	131,717,018	169,090,795	148,258,912	148,409,602	182,457,995	155,047,897	173,212,454	171,478,862	161,497,160	161,122,920	222,475,127	1,925,124,387
Total Distribution Line HC														
Carolinas	Caro Zone Ops Central	785	802	793	815	820	849	914	890	897	880	875	910	10,230
Carolinas	Caro Ops Coastal Zone	506	538	542	538	554	638	627	630	654	647	642	642	7,158
Carolinas	Caro Zone Ops Mountains	583	579	602	655	652	662	672	653	677	680	690	713	7,818
Carolinas	Caro Ops Pee Dee Zone	317	325	327	310	315	333	353	346	350	360	358	357	4,051
Carolinas	Caro Zone Ops Triad	496	517	521	532	556	562	561	538	555	583	579	589	6,589
Carolinas	Caro Zone Ops Triangle North	554	581	594	604	616	593	607	652	674	703	713	734	7,625
Carolinas	Caro Zone Ops Triangle South	595	564	598	632	642	665	671	659	637	647	644	641	7,595
Carolinas	Caro Zone Ops Upstate	579	601	619	616	633	644	641	644	661	670	682	675	7,665
Carolinas	All Other	-	-	-	-	-	-	-	-	-	-	-	-	-
Carolinas	Total Headcount	4,415	4,507	4,596	4,702	4,788	4,946	5,046	5,012	5,105	5,170	5,183	5,261	58,731
Estimated Annual Spend per HC														
Carolinas	Caro Zone Ops Central	304,010	375,244	418,572	348,352	357,112	483,109	312,141	497,932	407,879	355,492	285,607	636,787	400,289
Carolinas	Caro Ops Coastal Zone	230,287	318,275	409,827	340,087	375,475	401,175	337,831	377,549	442,148	287,172	350,076	443,123	361,929
Carolinas	Caro Zone Ops Mountains	241,639	294,736	430,933	368,518	322,237	439,239	391,368	366,075	403,088	460,429	327,111	354,750	368,365
Carolinas	Caro Ops Pee Dee Zone	406,535	316,709	498,108	483,510	434,191	423,997	400,469	432,924	516,069	408,844	407,901	497,310	435,711
Carolinas	Caro Zone Ops Triad	201,339	319,707	440,520	423,246	338,727	427,463	305,575	337,915	353,661	349,850	320,352	435,823	355,752
Carolinas	Caro Zone Ops Triangle North	226,576	369,581	395,605	375,123	361,021	450,370	383,331	417,667	368,893	348,107	433,784	606,001	399,176
Carolinas	Caro Zone Ops Triangle South	288,294	410,402	534,568	341,257	376,915	473,309	477,713	398,643	423,862	404,964	450,567	485,219	422,848
Carolinas	Caro Zone Ops Upstate	315,071	371,652	433,862	411,608	443,131	418,268	365,737	453,218	354,439	400,543	443,032	537,385	413,778
Carolinas	All Other	-	-	-	-	-	-	-	-	-	-	-	-	-
Carolinas	$ per HC - Month	**272,767**	**350,700**	**441,490**	**378,372**	**371,954**	**442,680**	**368,723**	**414,715**	**403,084**	**374,848**	**373,042**	**507,451**	**393,344**
Carolinas	$ per HC - YTD	272,767	312,135	356,115	361,859	363,960	377,888	376,486	381,527	384,079	383,091	382,117	393,344	

Customer Delivery Carolinas - Capital (CapEx) - Distribution Line Resource Forecast

Zone	Spend Category	Dec'22 YTD Actual	2023 Budget	2023 vs. Dec'22 YTD Actual
Central	Distribution Line Resourced Spend	341,246,448	358,212,463	16,966,015
Central	Not Distribution Line Resourced Spend	15,477,670	49,204,651	33,726,981
	Zone Total	**356,724,118**	**407,417,114**	**50,692,996**
Coastal	Distribution Line Resourced Spend	215,890,707	223,199,218	7,308,511
Coastal	Not Distribution Line Resourced Spend	20,863,891	25,898,925	5,035,034
	Zone Total	**236,754,598**	**249,098,143**	**12,343,545**
Mountains	Distribution Line Resourced Spend	239,989,661	274,995,648	35,005,987
Mountains	Not Distribution Line Resourced Spend	15,058,154	21,348,890	6,290,736
	Zone Total	**255,047,814**	**296,344,537**	**41,296,723**
PeeDee	Distribution Line Resourced Spend	147,088,842	159,768,264	12,679,422
PeeDee	Not Distribution Line Resourced Spend	13,620,948	21,677,841	8,056,892
	Zone Total	**160,709,790**	**181,446,105**	**20,736,315**
Triad	Distribution Line Resourced Spend	195,337,524	210,138,673	14,801,149
Triad	Not Distribution Line Resourced Spend	6,991,121	16,311,804	9,320,683
	Zone Total	**202,328,645**	**226,450,477**	**24,121,832**
Triangle No	Distribution Line Resourced Spend	253,643,115	291,631,000	37,987,885
Triangle No	Not Distribution Line Resourced Spend	24,040,525	14,033,944	(10,006,581)
	Zone Total	**277,683,640**	**305,664,944**	**27,981,304**
Triangle So	Distribution Line Resourced Spend	267,627,588	307,816,527	40,188,939
Triangle So	Not Distribution Line Resourced Spend	36,061,042	43,263,170	7,202,128
	Zone Total	**303,688,629**	**351,079,697**	**47,391,068**
Upstate	Distribution Line Resourced Spend	264,300,502	309,228,903	44,928,401
Upstate	Not Distribution Line Resourced Spend	13,531,715	42,569,062	29,037,347
	Zone Total	**277,832,217**	**351,797,965**	**73,965,748**
Region Oth	Distribution Line Resourced Spend	-	-	-
Region Oth	Not Distribution Line Resourced Spend	47,529,702	43,618,519	(3,911,183)
		47,529,702	**43,618,519**	**(3,911,183)**
Carolinas T	Distribution Line Resourced Spend	**1,925,124,387**	**2,134,990,696**	**209,866,309**
Carolinas T	Not Distribution Line Resourced Spend	193,174,767	277,926,806	84,752,039
		2,118,299,154	**2,412,917,502**	**294,618,348**

2022 Annual $ per HC	2023 Estimated HC	Jan'23 Actual HC	Variance to Jan'23 HC
400,289	895	930	35
361,929	617	642	25
368,365	747	708	(39)
435,711	367	355	(12)
355,752	591	571	(20)
399,176	731	759	28
422,848	728	649	(79)
413,778	747	697	(50)
	5,423	**5,311**	**(112)**

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-20, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-20
Page 1 of 1

Request:

20. For Rate Years 1 through 3, please provide the following information per Rate Year as deemed necessary to complete all the Company's proposed work, and reference any supporting documents. Please also reconcile these responses with the labor hour estimates contained in the "Grid Plan vShare" document provided in response to PS DR 62-1 for Substation and Line projects.
    a. Total hours of DEP employee craft and equivalent full-time employees.
    b. Total number of DEP trucks.
    c. List of specialized equipment/vehicles.
    d. Total hours of external vendor employee craft and equivalent full-time employees.
    e. Total number of external vendor trucks.
    f. Total hours of DEP project management and equivalent full-time employees.
    g. Total hours of vendor project management and equivalent full-time employees.
    h. Total hours of DEP engineers and equivalent full-time employees.
    i. Total hours of vendor engineers and equivalent full-time employees.
    j. Total aggregate hours for all work and equivalent full-time employees:
        i. DEP employees
        ii. Vendors
    k. List DEC resources used in the staffing and the equivalent full-time employees.
        i. If other DEP affiliate resources are required or expected to be utilized, please list those as well by affiliate.

Response:

Please see DEP's responses to PSDR 155-1 and 155-18. As stated in response to PS DR 155-18, for the Distribution function, resource forecasting (specifically craft/line labor) is performed in total for the Carolinas for all Distribution work scopes/projects. This method is used to ensure sufficient resources to complete all work. The forecast is performed annually and available for the next calendar year by the fourth quarter or when the following year's budget is finalized. See example in attachment DEP PSDR 155 – 20 Attachment.xlsx.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-21, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-21
Page 1 of 1

Request:

21. For equipment that either (1) takes 6 months or longer to procure and deliver or (2) is a single piece of equipment that is >$100k, identify the total amount of equipment costs and labor by Rate Year.

Response:

Please see DEP's responses to PSDR 155-4 and 155-18. The dynamic nature of the procurement and project development processes utilized by DEP (which is described in response to PSDR 155-1) renders this data request premature since final costs for individual pieces of equipment and the procurement timelines are not certain until equipment is actually ordered – which has not occurred in the vast majority of cases with regard to MYRP projects in DEP's MYRP.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-22, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-22
Page 1 of 1

Request:

22. For equipment that either (1) takes 9 months or longer to procure and deliver or (2) is a single piece of equipment that is >$300k, identify the total amount of equipment costs and labor by Rate Year.
    a. For Rate Year 1, has all the equipment (material cost) been ordered?

Response:

Please see DEP's responses to PSDR 155-4, 155-18 and 155-21.

**Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155**

Docket No. E-2, Sub 1300

**Date of Request: January 27, 2023
Date of Response: February 15, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-23, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-23
Page 1 of 1

Request:

23. For equipment that either (1) takes 12 months or longer to procure and deliver or (2) is a single piece of equipment that is >$200k, identify the total amount of equipment costs and labor by Rate Year.
    a. For Rate Year 1, has all the equipment (material cost) been ordered?

Response:

Please see DEP's responses to PSDR 155-4, 155-18 and 155-21.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-24, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-24
Page 1 of 1

Request:

24. For equipment that either (1) takes 18 months or longer to procure and deliver or (2) is a single piece of equipment that is >$200k, identify the total amount of equipment costs and labor by Rate Year.
    a. For Rate Year 1, has all the equipment (material cost) been ordered?
    b. For Rate Year 2, has all the equipment (material cost) been ordered?

Response:

Please see DEP's responses to PSDR 155-4, 155-18 and 155-21.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-25, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-25
Page 1 of 1

Request:

25. Provide a list of equipment by MYRP project that will take 24 months or longer to procure and deliver.
    a. For each project, list the date it was ordered or expects to be ordered.

Response:

Please see DEP's responses to PSDR 155-4, 155-18 and 155-21.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-26, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-26
Page 1 of 1

Request:

26. For the last 5 years, list annually the number of DEP distribution craft the Company has employed.
    a. List the total hours and equivalent full-time employees of DEP craft that have completed work toward construction-like projects, similar to the work scope in the MYRP (not including storm restoration activities or typical O&M-like work).

Response:

Headcount (NC DEP Only):
2018: 385
2019: 384
2020: 390
2021: 379
2022: 436

a. Hours for "construction-like" projects less storm restoration activities and typical O&M-like work:
Total Hours (NC DEP only):
2018: 341,882
2019: 457,644
2020: 521,184
2021: 509,830
2022: 564,126

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-27, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-27
Page 1 of 1

Request:

27. For the last 5 years, list annually the number of vendor craft the Company has contracted out.
    a. List the total hours and equivalent full-time employees of vendor craft that have completed work toward construction-like projects, similar to the work scope in the MYRP (not including storm restoration activities or typical O&M-like work).

Response:

Headcount (NC DEP Only):
2018: Information not available
2019: Information not available
2020: 972
2021: 1,132
2022: 1,241

a. Hours are not tracked for our vendor craft resources.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-28, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-28
Page 1 of 1

Request:

28. For the last 5 years, list annually key metrics the Company used to plan and prioritize work projects.
    a. Provide a detailed summary and supporting work papers of how the Company used historic metrics and trends to propose MYRP projects and completion by Rate Year.

Response:

On an annual basis, the Company utilizes the following approach to plan and prioritize distribution projects:
Nov-Jan: Capital planning specialists engage Subject Matter Experts (SMEs) cross-functionally to review and update 5-year plan assumptions and projections.
Feb-Mar: Capital planning specialists review plan updates to ensure alignment with operational needs, regulatory commitments, and jurisdictional constraints.
Mar-Apr: Capital planning leads collaborate with cross-function SMEs and leaders to prioritize/optimize plan based on operational & customer benefits. Key considerations include: jurisdictional investment constraints, operational needs, state-level commitments, safety/reliability improvements, operational efficiencies, etc.
Apr-May: Capital planning leads facilitate portfolio-level reviews of plan updates, key challenges and constraints with regional & functional leaders.
May-Jun: Capital planning leaders review proposed capital plan and key constraints & risks with business unit executive leadership team.
Jun-Aug: Capital planning and business unit leaders from major functions review consolidated enterprise-wide plans and discuss and mitigate key constraints & risks.

28(a) - Please see the supplemental response to DEP PSDR 78-16.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-29, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-29
Page 1 of 1

Request:

29. Does the Company have enough internal resources to complete the MYRP proposed work for Rate Years 1 through 3?
    a. If so, please provide the analysis used to make such a determination.
    b. If so, please provide a detailed narrative of what future assumptions the Company used in staffing and quantify that to a percentage of increase of existing staffing and equivalent full-time employees.
    c. If not, please provide a narrative and analysis used to make such a determination.
    d. If not, list which Rate Years the Company has identified internal staffing and workload related issues.
    e. If not, provide a detailed narrative and assumptions of external labor (vendor or affiliate) resources the Company needs to supplement their internal labor resources.
        i. List the total amount of work expected to be completed by internal versus external resources.
            1. Identify each external source of labor to the extent known.

Response:

Please see DEP's responses to PSDR 155-1 and 155-18. No, the Company does not have enough internal resources to complete all of the proposed work but, consistent with past practice, will continue to rely on external resources where needed in order to complete the work as explained further below.

(a.-b.) N/A

(c.-e.) The gap in line resources is determined first by using target budget numbers and dividing by average cost per resource, which yields a total number of resources needed to spend the target budget amount. The difference between this number and the number of internal resources represents the gap that must be filled by external resources.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-30, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-30
Page 1 of 1

Request:

30. By Rate Year, list the amount of overtime assumed to meet project schedules.
    a. List internal labor amounts of OT assumed.
    b. List external labor amounts of OT assumed.

Response:

Please see response to PSDR 155-20.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-31, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-31
Page 1 of 1

Request:

31. By Rate Year, list the Company's expected percentage of completion of each MYRP project and their respective costs.
    a. Provide supporting analysis.
    b. List the number of projects and project costs that are assumed to have greater than 90% certainty of being completed in the respective rate year.
    c. List the number of projects and project costs that are assumed to have 81% to 90% certainty of being completed in the respective rate year.
    d. List the number of projects and project costs that are assumed to have 71% to 80% certainty of being completed in the respective rate year.
    e. List the number of projects and project costs that are assumed to have 70% or less certainty of being completed in the respective rate year.

Response:

The Company is confident that the projects within each Rate Year can be completed. However, the Company further observes that the Commission itself has acknowledged the need for the Company to exercise discretion in implementing the MYRP in order to benefit customers. Therefore, it is likely that a variety of factors (including factors outside of the control of the Company) will require the Company to modify or adjust certain MYRP projects for the benefit for customers. The Company mitigates these events to the best of its ability. Please refer to "Guyton Direct Exhibit 4 - MYRP Distribution Project Detail" which reflects the Company's expected MYRP project completion by rate year and respective cost.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-32, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-32
Page 1 of 1

Request:

32. For each MYRP project, please indicate whether it has dependencies on other MYRP projects in prior rate years (e.g., if there is a Rate Year 2 Substation and Line project that is dependent upon a Rate Year 1 Substation and Line project's completion, describe the dependency).

Response:

Substation and Line
Dependencies (Yes/No) Yes
Dependency description: For SOG team installation, where the teams cross sub-stations between projects; to get the full team completion (complete backfeed capability for all circuits in the team) may require work to complete in both projects.

Retail and System Capacity
Dependencies (Yes/No) Yes
Dependency description: The retail and system capacity work are interdependent. The retail projects provide needed substation capacity and the related system projects are needed to transfer power from the substation to the customer load centers.

Hazard Tree
Dependencies (Yes/No) No
Dependency description

Facilities
Dependencies (Yes/No) No
Dependency description

Fleet
Dependencies (Yes/No) No
Dependency description:

Mission Critical Transport
Dependencies (Yes/No) No
Dependency description: Dependencies are not on other projects in the MYRP; they are on local governments and land services, wildlife, etc.

Towers, Shelters, Power Supply
Dependencies (Yes/No) No
Dependency description: Dependencies are not on other projects in the MYRP; they are on local governments and land services, wildlife, etc.

Land Mobile Radio
Dependencies (Yes/No) Yes
Dependency description: LMR is dependent upon some of the Towers Shelters Power

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-32
Page 2 of 2

Supply workstream for certain towers to be completed that will also support the LMR effort.

ADMS
Dependencies (Yes/No) Yes
Dependency description: DMS/OMS/SCADA products are independent Duke software assets, but the projects are dependent upon each other for versioning and compatibility. When the Company performs upgrades to one system, typically we upgrade the other, to match the newer version for functionality purposes. CLFISR can work independent of a DMS upgrade, however the CLFISR project does depend upon the DMS upgrade to unlock full capabilities.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-33, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-33
Page 1 of 1

Request:

33. For calendar years 2019, 2020, 2021, and 2022, please provide the following information for each year:
    a. Total number of internal FTEs assigned to distribution projects.
    b. Total number of external FTEs assigned to distribution projects.
    c. Total number of internal labor hours charged to distribution projects.
    d. Total number of external labor hours charged to distribution projects.

Response:

33-a
2019: 560
2020: 577
2021: 559
2022: 563
FTE's were estimated based on the hours below

33-b: Information is not available for this population of external FTE's

33-c
2019: 932,055 hours
2020: 960,235 hours
2021: 929,817 hours
2022: 937,354 hours

33-d: Information is not available for this population of external FTE's

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-34, was provided to me by the following individual(s): Linda K. Costantino, Lead Planning & Regulatory Support Specialist, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-34
Page 1 of 1

Request:

34. For calendar years 2023, 2024, 2025, and 2026, please provide the following information for each year for MYRP and non-MYRP related work that is currently planned or expected:

    a. Total number of internal FTEs assigned to distribution projects.
    b. Total number of external FTEs assigned to distribution projects.
    c. Total number of internal labor hours charged to distribution projects.
    d. Total number of external labor hours charged to distribution projects.

Response:

As stated in response to PSDR 155-20, the information for 2023 is provided as an example of the craft line distribution forecast. The forecast is performed on an annual basis and is available for the next calendar year by the fourth quarter, or whenever the budget is finalized. As mentioned in response to PSDR 155-19, the forecasted spend for the Distribution function for 2024 and beyond is expected to be relatively consistent with 2023. As such, the Company does not anticipate the need for a significant increase in craft/line resources beyond what is forecasted for 2023.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-35, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-35
Page 1 of 1

Request:

35. Please identify key staffing and labor metrics the Company typically uses to evaluate work projects, work project completion, and timeline management.

Response:

The Nuclear function is confident in its ability to execute the nuclear projects within the MYRP as the Company has been doing these types of projects for years and thus, is experienced in executing this type of work. For Nuclear capital projects, an initial budgetary estimate is entered into the Long Range Plan for an investment based on a high level estimate with a general outline of resource mix and high level timeline.

Once the first budget year for a particular investment arrives, a detailed estimate is produced that includes a work breakdown structure of exactly what scopes of work will be completed, by what type of resource (internal, external, contract vendor), as well as a Primavera P6 schedule that matches the estimated spend. Once this advance funding process is approved, the project estimate and schedule are loaded into a Project Status Tool with the associated staffing (internal, external, contract vendor), correlated rates are applied and cashflow by month is reviewed. The Project Status Tool also contains data from Primavera P6 with schedule activities, baseline dates and forecasted dates to determine if any schedule activities are off course.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-36, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-36
Page 1 of 1

Request:

36. For Rate Years 1 through 3, list each of the Company's key staffing and labor metrics along with the respective scores/requirements of each.
    a. If the Company did not perform such an analysis, please explain why not.

Response:

Please refer to the Company's response to PSDR 155-35. The Company has not performed the analysis requested in PSDR 155-36 due to the nature of the varying types of projects, resource needs, and operational conditions impacting timing of construction; but, for the reasons explained in the response to PSDR 155-35 and throughout these responses, is confident that the projects proposed for each Rate Year will be completed.

The Nuclear organization does not "score" staffing and labor requirements for individual projects. As part of the funding estimate and schedule development, a mix of resources is estimated and each team (Project Management, Engineering, Implementation, Planning, and Station Support) evaluates the resource need for their area based on the amount of work planned for the project. If internal staff is already fully allocated to other activities, the project team will estimate contingent workforce, and once approved, the appropriate manager will source for an external contingent worker or vendor firm to fulfill the work requirement. The closer in time to the project, the more detailed the estimates becomes, including hours.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-37, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-37
Page 1 of 1

Request:

37. Describe whether the Company's view of Nuclear-related work for capital projects relies more on external vendor support and/or delivery schedules than the work required for reconducting a line or designing and building a new substation.

Note: the intent of the question is to have the Company explain the discrete differences among business units and how some business units may rely more on external vendors given the unique project and/or skill sets.

Response:

The Company has not performed the requested comparison. However, the Company can confirm that all projects executed in Nuclear will have a mix of internal and external workers, both staff augmentation and vendor contracts. Similar to the Distribution and Transmission functions, the Nuclear organization has engineers of choice to back up the Company when external resources are determined to be needed, as well as preferred vendors for craft labor, that the Company has experience working with to complete projects.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-38, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-38
Page 1 of 1

Request:

38. For Rate Years 1 through 3, please provide the following per Rate Year as deemed necessary to complete all the Company's proposed work:
   a. Total hours of DEP employees and equivalent full-time employees
   b. Total hours of external vendor employees and equivalent full-time employees.
   c. Total hours of DEP project management and equivalent full-time employees
   d. Total hours of vendor project management and equivalent full-time employees
   e. Total hours of DEP engineers and equivalent full-time employees.
   f. Total hours of vendor engineers and equivalent full-time employees.
   g. Total aggregate hours for all work and equivalent full-time employees:
      i. DEP employees
      ii. Vendors
   h. List all DEC resources used in the staffing and the equivalent full-time employees.

Response:

See the Company's response to PSDR 155-35 and staffing data provided in attachment "DEP PSDR 155 combined data - Nuclear."

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-39, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-39
Page 1 of 1

Request:

39. For equipment that either takes 6 months or longer to procure and deliver or for a single piece of equipment that is >$200k, identify the total amount of equipment costs and labor by Rate Year.

Response:

To the extent available, for projects with identified procurements, this information is provided in the attached file "DEP PSDR 155 combined data - Nuclear."

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-40, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-40
Page 1 of 1

Request:

40. For equipment that either takes 9 months or longer to procure and deliver or for a single piece of equipment that is >$200k, identify the total amount of equipment costs and labor by Rate Year.
    a. For Rate Year 1, has all the equipment (material cost) been ordered?

Response:

Please see the Company's response to PSDR 155-39.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-41, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-41
Page 1 of 1

Request:

41. For equipment that either takes 12 months or longer to procure and deliver or for a single piece of equipment that is >$200k, identify the total amount of equipment costs and labor by Rate Year.
    a. For Rate Year 1, has all the equipment (material cost) been ordered?

Response:

Please see the Company’s response to PSDR 155-39.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-42, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-42
Page 1 of 1

Request:

42. For equipment that either takes 18 months or longer to procure and deliver or for a single piece of equipment that is >$200k, identify the total amount of equipment and labor costs by Rate Year.
    a. For Rate Year 1, has all the equipment (material cost) been ordered?
    b. For Rate Year 2, has all the equipment (material cost) been ordered?

Response:

Please see the Company's response to PSDR 155-39.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-43, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-43
Page 1 of 1

Request:

43. Provide a list of all equipment by MYRP project that will take 24 months or longer to procure and deliver.
    a. For each project, list the date it was ordered or expects to be ordered.

Response:

Please see the Company's response to PSDR 155-39.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1300
PSDR 155-44

YEAR	REGULAR HOURS	OVERTIME HOURS	TOTAL HOURS	FTE EQUIVALENT
2018	325,688.80	54,725.70	380,414.50	182.9
2019	213,356.10	32,522.50	245,878.60	118.2
2020	143,426.30	771,057.40	156,400.50	75.2
2021	177,624.20	14,337.80	191,962.00	92.3
2022	198,901.90	20,879.80	219,781.70	105.7

Notes:
Does not include unproductive hours allocated to capital (i.e., sick, vacation, holiday, etc.)
Does not include allocated overhead for support departments that indirectly support capital work
Does not include hours charged to RWIP, Study Projects, or Nuclear Fuel

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-44, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-44
Page 1 of 1

Request:

44. For the last 5 years, list annually the number of DEP staff used for nuclear related work the Company has employed.
    a. List the total hours and equivalent full-time employees of DEP staff that have completed work toward construction-like projects, similar to the work scope in the MYRP (not including typical O&M-like work).

Response:

Please see attachment "DEP PSDR 155-44 - Nuclear."

Duke Energy Progress, LLC
Docket No. E-2, Sub 1300
PSDR 155-45

YEAR	CW Dollars Charged to Capital			
2018	112,650,353.70			
2019	89,133,789.80			
2020	38,409,190.90			
2021	58,499,300.20			
2022	64,507,859.40			

Notes:
Only a limited number of contractor hours are tracked.
Therefore, dollars charged by contingent workers (CW) to capital were included to provide a perspective for tl

he volume of CWs utilized by year.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-45, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-45
Page 1 of 1

Request:

45. For the last 5 years, list annually the number of vendor craft the Company has contracted out.
    a. List the total hours and equivalent full-time employees of vendor craft that have completed work toward construction-like projects, similar to the work scope in the MYRP (not including typical O&M-like work).

Response:

Please see attachment "DEP PSDR 155-45 - Nuclear." Note that only a limited number of contractor hours are tracked. Therefore, dollars charged by contingent workers (CW) to capital were included to provide a perspective for the volume of CWs utilized by year.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-46, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-46
Page 1 of 1

Request:

46. For the last 5 years, list annually key metrics the Company would use to plan and prioritize work projects.
    a. Provide a detailed summary and supporting work papers of how the Company used historic metrics and trends to propose MYRP projects and completion by Rate Year.

Response:

Please see the Company's response to PSDR 155-35.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-47, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-47
Page 1 of 1

Request:

47. Does the Company have enough internal resources to complete the MYRP proposed work for Rate Years 1 through 3.
    a. If so, please provide the analysis used to make such a determination.
    b. If so, please provide a detailed narrative of what future assumptions the Company used in staffing and quantify that to a percentage of increase of existing staffing and equivalent full-time employees.
    c. If not, please provide a narrative and analysis used to make such a determination.
    d. If not, list which Rate Years the Company has identified internal staffing and workload related issues.
    e. If not, provide a detailed narrative and assumptions of external labor (vendor or DEC) resources the Company needs to supplement their internal labor resources.
        i. List the total amount of work expected to be completed by internal versus external resources.
            1. Identify each external source of labor to the extent known.

Response:

The Company will use Duke Direct employees, Contingent Workers, Contracts and Engineers of Choice ("EOC") to complete the capital projects on the MYRP as it does other capital projects. Resources will be added and deleted to fit the size of the portfolio and needs of the Company and resource needs will be determined as the projects are funded. The resource needs are identified in the Cost Breakdown Structure and cashflows provided in response to PSDR 155-38 above. As noted in the response to PSDR 155-37, the Nuclear organization has engineers of choice to back up the Company when external resources are determined to be needed, as well as preferred vendors for craft labor, that the Company experience working with to complete projects.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-48, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-48
Page 1 of 1

Request:

48. By Rate Year, list the amount of overtime assumed to meet project schedules.
    a. List internal labor amounts of OT assumed.
    b. List external labor amounts of OT assumed.

Response:

For projects that have identified OT assumptions, see attachment “DEP PSDR 155 combined data - Nuclear.”

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-49, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-49
Page 1 of 1

Request:

49. By Rate Year, list the Company's expected percentage of completion of each MYRP project and their respective costs.
    a. Provide supporting analysis.
    b. List the number of projects and project costs that are assumed to have greater than 90% certainty of being completed in the respective rate year.
    c. List the number of projects and project costs that are assumed to have 81% to 90% certainty of being completed in the respective rate year.
    d. List the number of projects and project costs that are assumed to have 71% to 80% certainty of being completed in the respective rate year.
    e. List the number of projects and project costs that are assumed to have 70% or less certainty of being completed in the respective rate year.

Response:

Please see DEP's response to PS DR 155-35. The Company is confident that the nuclear projects within DEP's MYRP can be completed. However, the Company further observes that the Commission itself has acknowledged the need for the Company to exercise discretion in implementing the MYRP in order to benefit customers. Therefore, it is likely that a variety of factors (including factors outside of the control of the Company) will require the Company to modify or adjust certain MYRP projects for the benefit of customers.

The Nuclear MYRP projects are not unique with respect to how the Nuclear organization plans and executes its work and do not represent a material increase in nuclear work over the MYRP period beyond what would be done regardless. These projects are a subset of the work that needs to be done for the nuclear fleet in the coming years and represent high priority work that must be completed. The Nuclear organization has experience developing and executing similar work and is confident it will have the resources necessary to complete the work in the time frame planned.

**Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155**

Docket No. E-2, Sub 1300

**Date of Request: January 27, 2023
Date of Response: February 15, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-50, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-50
Page 1 of 1

Request:

50. For each MYRP project, please indicate whether it has dependencies on other MYRP projects in prior rate years (e.g., if there is a Rate Year 2 I&C project that is dependent upon a Rate Year 1 equipment installation completion, describe the dependency).

Response:

Please see attachment "DEP PSDR 155 combined data – Nuclear" for projects with identified dependencies.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-51, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-51
Page 1 of 1

Request:

51. For each MYRP project in Rate Years 1 through 3, answering the following:
    a. Is the project already underway?
    b. Total percentage of work already completed.
    c. Is the work already under contract and/or is there an executed purchase order with a vendor?
        i. Does the vendor schedule align with the Company's proposed MYRP schedule?
    d. Is installation and commissioning of the project already included in the proposed outage plans?
    e. Has the project been identified on critical path?
        i. If the project has been identified on critical path, list the number of days on critical path.
        ii. If the project has not been identified on critical path, is this because the project is proposed to have no issues, or is it that an outage plan has not been created and therefore there is no critical path?
    f. If the Commission does not approve the MYRP, will the Company continue with the proposed project(s) in each respective Rate Year?
        i. If not, why not?

Response:

For parts (a)-(e), please see attachment "DEP PSDR 155 combined data - Nuclear." Seven of the 24 projects have not yet started. However, Nuclear selected the MYRP projects because they are discrete, identifiable high priority projects that need to be done to maintain the reliability of the nuclear fleet, and the Nuclear organization is confident about their cost and schedule. As noted earlier, these projects are not unique to the organization with respect to how it plans and executes its work and are not "extra" work that is in addition to the work the organization will do over the MYRP period. Rather, these projects represent a subset of the projects that will be done over the next few years to keep the nuclear fleet reliable and in efficient working condition.

(c)(i). Yes, vendor schedules align with the MYRP schedule as proposed.

(f)(i). Yes, DEP will continue with the proposed project(s) in each respective Rate Year if not approved by the Commission due to the plant reliability, safety, and/or efficiency aspects related to each investment.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-52, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-52
Page 1 of 1

Request:

52. For calendar years 2019, 2020, 2021, and 2022, please provide the following information for each year:
    a. Total number of internal FTEs assigned to nuclear projects.
    b. Total number of external FTEs assigned to nuclear projects.
    c. Total number of internal labor hours charged to nuclear projects.
    d. Total number of external labor hours charged to nuclear projects.

Response:

Please see the Company's responses to PSDR 155-44 and 45.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-53, was provided to me by the following individual(s): Stephen Thornton, Nuclear Regulatory Strategy Director, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-53
Page 1 of 1

Request:

53. For calendar years 2023, 2024, 2025, and 2026, please provide the following information for each year for MYRP and non-MYRP related work that is currently planned or expected:
    a. Total number of internal FTEs assigned to nuclear projects.
    b. Total number of external FTEs assigned to nuclear projects.
    c. Total number of internal labor hours charged to nuclear projects.
    d. Total number of external labor hours charged to nuclear projects.

Response:

The current projection for internal FTEs assigned to nuclear projects is expected to remain flat for 2023, 2024, 2025 and 2026. Resources will be added and removed to fit the size of the portfolio and needs of the Company, based on approved funding packages.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-54, was provided to me by the following individual(s): Melinda McGrath, Outside Counsel, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-54
Page 1 of 1

Request:

54. Provide a general narrative of any additional factors, items, metrics, scoring, or other items the Company considered to be legitimate constraints on project management, project planning, and resource loading, and how each is reflected in the proposed MYRP by Rate Year.

Response:

Materials and labor requirements for projects are managed at the functional level. Each of the functions that are the subject of this request (transmission, distribution and nuclear) are confident in their ability to execute the projects that are included in DEP's MYRP because the projects are not "new" projects in terms of scope. The majority of the projects included in DEP's MYRP are projects similar in scope to projects that the Company has successfully completed and the Company plans to adhere to its well-established processes in implementing the MYRP projects, including those processes related to obtaining needed labor and materials.

Below are some general, "enterprise level" comments pertaining to materials and labor:

Materials: Historically, the Company ordered materials on an as-needed basis, taking into consideration stocking levels and lead times. Now, to mitigate any potential supply chain constraints, Duke Energy has developed a proactive approach to ensuring it has sufficient materials to complete necessary work, including placing forward orders. These measures not only help the Company secure supply, but also identify potential gaps in sufficient time to allow for mitigation efforts such as identifying new suppliers and modifying specifications where necessary. Duke's materials strategy factors in capital projects and expected ongoing work associated with customer additions, storm response, and other maintenance work.

Labor: Individual functions within the Company assess the type of work to be performed and match the type of work to the appropriate labor classification to ensure there is appropriate bandwidth to accommodate all customer needs. Broadly speaking, for some types of projects, e.g., capital projects and economic development, the Company is able to plan ahead to ensure adequate resource levels are available, and often relies on historical experience. For example, as noted above and in previous responses, the transmission projects that are included in DEP's MYRP are generally similar in scope to the types of transmission projects that the Company has successfully completed (e.g., substation work, system intelligence and transformer work). Therefore, the transmission function intends to draw upon its years of experience and successful past practices with respect to staffing and labor metrics. For work that is not capable of being planned in advance (e.g., storm response and repairing equipment due to car accidents), the Company relies on historical data to estimate future resource needs.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-55, was provided to me by the following individual(s): Melinda McGrath, Outside Counsel, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-55
Page 1 of 1

Request:

55. For calendar years 2019, 2020, 2021, and 2022, please provide the following information for each year:
    a. Total number of internal FTEs assigned to all projects and typical work.
    b. Total number of external FTEs assigned to all projects and typical work.
    c. Total number of internal labor hours charged to all projects and typical work.
    d. Total number of external labor hours charged to all projects and typical work.

Response:

Pursuant to a discussion with Staff and the Company on February 10, 2023, Staff agreed to withdraw this request.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 155

Docket No. E-2, Sub 1300

Date of Request: January 27, 2023
Date of Response: February 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 155-56, was provided to me by the following individual(s): Melinda McGrath, Outside Counsel, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 155
DEP Docket No. E2, Sub 1300
Item No. 155-56
Page 1 of 1

Request:

56. For calendar years 2023, 2024, 2025, and 2026, please provide the following information for each year for MYRP and non-MYRP related work that is currently planned or expected:
    a. Total number of internal FTEs assigned to all projects and typical work.
    b. Total number of external FTEs assigned to all projects and typical work.
    c. Total number of internal labor hours charged to all projects and typical work.
    d. Total number of external labor hours charged to all projects and typical work.

Response:

Pursuant to a discussion with Staff and the Company on February 10, 2023, Staff agreed to withdraw this request.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 232

Docket No. E-2, Sub 1300

Date of Request: February 28, 2023
Date of Response: March 14, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 232-1, was provided to me by the following individual(s): Joanna Cormier, Director Carolinas Forecasting and Planning, and provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 232
DEP Docket No. E2, Sub 1300
Item No. 232-1
Page 1 of 1

Request:

1. For each business group/jurisdiction (distribution, transmission, nuclear, hydro, etc.) please provide the actual CapEx spend by month for January 1, 2019 through February 1, 2023.

Response:

Please see attachment "DEP DR 232 1 & 2 Support" for this information. The Company will supplement this response to include January 2023 data once it becomes available.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 232

Docket No. E-2, Sub 1300

Date of Request: February 28, 2023
Date of Response: March 14, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 232-2, was provided to me by the following individual(s): Joanna Cormier, Director Carolinas Forecasting and Planning, and provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 232
DEP Docket No. E2, Sub 1300
Item No. 232-2
Page 1 of 1

Request:

2. For each business group/jurisdiction (distribution, transmission, nuclear, hydro, etc.) please provide the budgeted CapEx spend by month for January 1, 2019 through February 1, 2023.

Response:

Please see attachment "DEP DR 232 1 & 2 Support" for this information. The Company will supplement this response to include January - February 2023 data once it becomes available.

Response to PSDR 232 - 1&2
Docket No. E-2, Sub 1300

Duke Energy Progress - 2019	Jan Actual	Jan Budget	Feb Actual	Feb Budget
Nuclear & RRE	56	77	39	65
Transmission	18	19	26	22
Distribution	47	49	64	48
Other*	11	14	15	14
Total Capital	**131**	**159**	**144**	**149**
Duke Energy Progress - 2020	**Jan Actual**	**Jan Budget**	**Feb Actual**	**Feb Budget**
Nuclear & RRE	55	59	20	31
Transmission	10	26	22	21
Distribution	62	68	45	59
Other*	12	14	9	12
Total Capital	**138**	**168**	**96**	**123**
Duke Energy Progress - 2021	**Jan Actual**	**Jan Budget**	**Feb Actual**	**Feb Budget**
Nuclear & RRE	27	50	61	53
Transmission	1	3	5	3
Distribution	43	53	37	52
Other*	(1)	7	12	10
Total Capital	**69**	**112**	**115**	**117**
Duke Energy Progress - 2022	**Jan Actual**	**Jan Budget**	**Feb Actual**	**Feb Budget**
Nuclear & RRE	29	68	30	36
Transmission	18	28	25	30
Distribution	50	63	63	68
Other*	23	14	24	34
Total Capital	**120**	**173**	**143**	**169**

*The category "Other" includes all capital spend other than Nuclear, RRE, Transmission and Dis

Mar Actual	Mar Budget	Apr Actual	Apr Budget	May Actual	May Budget	Jun Actual	Jun Budget
66	81	50	64	83	89	69	60
22	23	30	23	22	22	25	18
62	58	59	49	65	52	70	56
13	12	11	14	11	18	11	27
163	**173**	**150**	**150**	**180**	**180**	**175**	**160**

Mar Actual	Mar Budget	Apr Actual	Apr Budget	May Actual	May Budget	Jun Actual	Jun Budget
36	54	24	30	21	35	35	44
17	27	22	21	20	20	23	19
66	59	51	59	53	55	52	56
11	17	11	14	8	13	9	16
130	**156**	**108**	**124**	**102**	**124**	**119**	**135**

Mar Actual	Mar Budget	Apr Actual	Apr Budget	May Actual	May Budget	Jun Actual	Jun Budget
64	69	77	77	40	57	28	24
4	5	4	4	23	35	37	26
51	62	52	50	49	59	51	57
16	7	13	21	19	24	17	41
136	**142**	**147**	**152**	**132**	**174**	**133**	**149**

Mar Actual	Mar Budget	Apr Actual	Apr Budget	May Actual	May Budget	Jun Actual	Jun Budget
(31)	65	21	30	80	106	69	53
24	37	22	35	36	37	30	39
86	69	66	74	78	75	87	87
10	32	20	31	9	30	16	31
89	**203**	**129**	**170**	**203**	**248**	**202**	**209**

tribution. This would include spend such as new renewables projects, IT, security, customer connect, etc.

Jul Actual	Jul Budget	Aug Actual	Aug Budget	Sep Actual	Sep Budget	Oct Actual	Oct Budget
94	76	71	44	68	48	97	40
17	19	25	19	22	19	31	16
70	49	59	49	72	49	58	51
8	23	9	21	10	22	14	20
189	**166**	**164**	**132**	**171**	**138**	**200**	**126**

Jul Actual	Jul Budget	Aug Actual	Aug Budget	Sep Actual	Sep Budget	Oct Actual	Oct Budget
21	39	18	39	78	63	38	37
20	23	30	20	24	21	27	25
37	68	53	56	47	54	55	52
8	14	10	16	9	16	14	18
86	**144**	**110**	**130**	**159**	**154**	**133**	**132**

Jul Actual	Jul Budget	Aug Actual	Aug Budget	Sep Actual	Sep Budget	Oct Actual	Oct Budget
33	33	17	24	65	59	18	(3)
28	30	35	31	35	38	32	49
50	58	55	54	60	54	64	55
17	23	18	26	21	8	15	15
128	**144**	**125**	**135**	**181**	**160**	**129**	**116**

Jul Actual	Jul Budget	Aug Actual	Aug Budget	Sep Actual	Sep Budget	Oct Actual	Oct Budget
61	64	59	62	78	77	58	48
32	29	39	32	31	34	37	30
81	88	81	83	92	82	78	73
17	27	8	23	11	24	6	22
191	**207**	**188**	**200**	**211**	**217**	**178**	**174**

Nov Actual	Nov Budget	Dec Actual	Dec Budget	2019A	2019B
49	48	104	101	846	794
21	13	25	13	283	225
45	46	14	53	683	608
13	18	25	23	151	223
128	**125**	**168**	**191**	**1,962**	**1,850**
Nov Actual	Nov Budget	Dec Actual	Dec Budget	2020A	2020B
34	29	81	98	460	558
23	23	31	22	269	268
46	51	69	61	636	699
11	15	30	16	142	181
113	**118**	**212**	**198**	**1,507**	**1,706**
Nov Actual	Nov Budget	Dec Actual	Dec Budget	2021A	2021B
13	21	98	70	541	533
36	38	29	28	270	289
58	45	63	52	634	652
22	11	17	26	186	218
129	**115**	**208**	**176**	**1,631**	**1,692**
Nov Actual	Nov Budget	Dec Actual	Dec Budget	2022A	2022B
59	43	143	125	654	778
37	25	37	36	365	392
85	77	100	86	947	925
17	22	20	22	184	313
197	**167**	**300**	**269**	**2,150**	**2,408**

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 232

Docket No. E-2, Sub 1300

Date of Request: February 28, 2023
Date of Response: March 14, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 232-3, was provided to me by the following individual(s): Joanna Cormier, Director Carolinas Forecasting and Planning, and provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 232
DEP Docket No. E2, Sub 1300
Item No. 232-3
Page 1 of 1

Request:

3. The Public Staff has requested information previously on non-MRYP capital project spend through the MYRP period for Distribution and Transmission (reference PS DR 78-16 and 75-2). Please provide the expected/budgeted non-MYRP capital spend amount for each business group/jurisdiction (distribution, transmission, nuclear, hydro, etc.) by month from May,1st 2023 through October 1, 2026.

Response:

Please see attachment "DEP DR 232 3 & 4" for this information.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 232

Docket No. E-2, Sub 1300

Date of Request: February 28, 2023
Date of Response: March 14, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 232-4, was provided to me by the following individual(s): Joanna Cormier, Director Carolinas Forecasting and Planning, and provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 232
DEP Docket No. E2, Sub 1300
Item No. 232-4
Page 1 of 1

Request:

4. The Public Staff has requested information previously on non-MRYP capital project spend through the MYRP period for Distribution and Transmission (reference PS DR 78-16 and 75-2). Please provide the expected/budgeted non-MYRP capital spend amount for each business group/jurisdiction (distribution, transmission, nuclear, hydro, etc.) by month from May,1st 2023 through October 1, 2026.

Response:

Please see attachment "DEP DR 232 3 & 4" for this information.

Response to PSDR 232 - 3&4
Docket No. E-2, Sub 1300

Duke Energy Progress	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23
MYRP Capex*							
Nuclear & RRE	17	18	19	18	18	19	17
Transmission	33	34	35	37	39	40	44
Distribution	50	51	55	57	53	64	71
Other**	0	0	0	3	3	3	7
Total MYRP Capex	100	103	109	116	114	126	139
Non-MYRP Capex							
Nuclear & RRE	13	8	10	7	6	8	11
Transmission	9	8	8	8	8	8	8
Distribution	29	28	30	31	29	30	27
Other**	15	15	14	14	13	14	14
Total Non-MYRP Capex	65	60	62	60	57	61	60
Total Capex******							
Nuclear & RRE	30	26	29	26	25	28	28
Transmission	41	43	44	46	47	48	53
Distribution	80	79	84	88	83	94	97
Other**	15	15	14	17	16	16	21
Total Capex	166	163	171	176	171	187	199

*Only includes capex spend for the 3 year MYRP proposed in this rate case. Any spend for future MYRP
**The category "Other" includes all capital spend other than Nuclear, RRE, Transmission and Distribution.
***The financial plan does not focus on monthly shaping of capex in the out-years. However, consideratio
****Does not foot due to rounding

Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24
14	13	27	27	27	27	19	13	20	20	12	11	9
41	38	37	36	36	35	34	34	33	35	33	33	31
71	76	67	65	66	63	58	58	57	55	54	55	54
7	7	12	12	12	14	14	14	19	19	19	22	33
133	133	143	140	142	138	125	119	130	128	117	120	127
8	13	(1)	(1)	8	9	18	13	6	5	15	25	29
8	10	5	5	6	6	6	6	6	6	6	6	6
27	39	29	27	30	32	33	34	35	34	34	31	31
14	44	24	24	25	25	26	26	25	25	26	26	27
57	106	57	55	68	72	82	78	72	69	81	88	92
22	26	26	26	35	36	36	26	26	25	27	36	38
49	47	42	41	42	40	40	40	39	40	39	39	37
98	115	95	92	96	95	90	92	93	88	88	86	85
21	51	36	36	37	39	39	39	44	44	45	48	60
190	239	200	196	210	210	207	197	202	198	198	208	219

periods (after the initial 3 years) is included in the Non-MYRP category.

This would include spend such as new generation for solar, battery, and hydro, IT, security, customer connect, etc. Ongoing

n was given to shaping the MYRP capex given the focus on these projects in this rate case. As such, the non-MYRP capex a

Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
6	12	12	13	13	12	12	12	12	11	11	9	8
28	26	26	25	27	27	26	24	25	25	25	24	21
60	43	43	43	43	43	43	43	43	43	43	43	43
33	27	27	27	21	21	21	8	3	3	4	4	2
127	107	108	108	104	104	103	88	83	83	84	80	74
40	8	9	13	10	13	13	8	8	14	15	17	112
6	10	10	10	10	10	10	10	10	10	10	10	10
41	51	51	51	51	51	51	51	51	51	51	51	53
28	53	53	54	53	54	54	53	53	54	54	54	55
114	121	123	127	124	127	127	121	122	128	129	132	229
45	20	21	25	23	25	25	20	20	25	27	26	120
34	35	36	35	37	36	36	34	35	35	35	34	31
101	94	94	94	94	94	94	94	94	94	94	94	95
60	80	80	80	75	75	75	62	56	56	57	58	58
241	229	230	234	228	230	230	209	204	211	213	211	304

maintenance capital related to new generation assets is included in the "Nuclear & RRE" category as the RRE function takes
ppears to have negative and/or "lumpy" capex across months and should really be evaluated on an annual basis.

Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26
7	7	7	6	6	2	2	2	2
16	16	16	16	12	12	8	8	6
7	7	7	7	7	7	7	7	7
4	4	4	3	3	3	2	2	2
34	34	34	32	28	24	19	19	17
15	15	17	16	27	21	20	20	20
24	24	24	24	24	24	24	24	24
85	85	85	85	84	85	85	85	85
91	91	91	91	91	91	83	83	83
215	215	216	216	226	221	212	212	212
22	22	24	22	33	23	22	22	22
40	40	40	40	36	36	32	32	31
92	92	92	92	91	92	92	92	92
95	95	95	95	94	94	85	85	85
248	248	251	248	254	244	231	231	229

s over ongoing maintenace of the sites after being built.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 232

Docket No. E-2, Sub 1300

Date of Request: February 28, 2023
Date of Response: March 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 232-5, was provided to me by the following individual(s): Linda Costantino, Lead Planning and Regulatory Support Specialist, and provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 232
DEP Docket No. E2, Sub 1300
Item No. 232-5

Request:

5. In response to PS DR 155-29 c-e, Distribution, the Company stated: "The gap in line resources is determined first by using target budget numbers and dividing by average cost per resource, which yields a total number of resources needed to spend the target budget amount. The difference between this number and the number of internal resources represents the gap that must be filled by external resources." Nevertheless, the question for sub part 155-29(e) (i) asked: "List the total amount of work expected to be completed by internal versus external resources." It appears that the Company has a methodology to determine the gap in internal and external resources; however, the Company did not answer the question asked regarding the amount of work that will be completed by internal or external resources. The Public Staff cannot determine the viability of the Company's proposed MYRP plans/projects without discerning labor constraints and plans to address the "gap". Please answer the following questions for all MYRP projects by business unit/jurisdiction (distribution, transmission, nuclear, hydro, etc.):
    a. Using the Company's methodology stated in response to PS DR 155-29 (c-e), list by rate year or each month of the rate year if a monthly amount is more aligned with staffing and budgeting (the Company can choose the monthly or rate year metric) the resources needed from both internal and external staffing sources to implement the MYRP.
        i. For internal staffing, list the Company's 2022 internal staffing (full time equivalent employees or any other metric that the Company believes is accurate or a reasonable metric) that could complete MYRP tasks or MYRP-like tasks.
        ii. List the "gap" of resources needed to complete all of the Company's proposed projects in the MYRP.

Response:

a. As reflected in the DEP PS DR 155-20 Attachment, the 2023 Estimated Headcount need is 5,423. As stated in DEP DS DR 155-19, the forecasted spend for the Distribution function for 2024 and beyond is expected to be somewhat consistent with 2023. As such, the Company does not anticipate the need for a significant increase in craft/line resources beyond what is forecasted for 2023.

i. The DEP NC internal line headcount as of the end of 2022 was 436 (as submitted in response to PS DR 2-9 in Docket No. M-100 Sub 163).
ii. As stated in response to DEP PS DR 155-18, for the Distribution function, resource forecasting (specifically craft/line labor) is performed in total for the Carolinas for all Distribution work scopes/projects. The most recent resource forecasting was performed for the planned budget for 2023. The resource forecasting methodology takes the planned/estimated spend and uses a historical spend per line resource metric to determine the number of resources needed to execute the planned/estimated amount of spend. The resulting resource forecast is compared to current headcount to determine what actions if

any are needed to support the forecasted resource need. This resource forecasting includes internal and external resources.

In the DEP PS DR 155-20 Attachment, the 2023 Estimated Headcount need is 5,423. The total internal line headcount as of this analysis was 1,210 leaving a remaining need of 4,213. This is consistent with our current external line headcount of 4,101, leaving a gap of 112 resources (2% of the need). This is a minimal gap and can be managed with a variety of resourcing strategies such as flexing work schedules or Engineering turnkey contracts (EPC).

The Company analyzes Labor resource needs for subsequent years based on the budget and current labor resources to identify and fill any resource gaps. The Company intends to continue to follow this same process throughout the duration of the MYRP to ensure successful execution of the work plan.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 232

Docket No. E-2, Sub 1300

Date of Request: February 28, 2023
Date of Response: March 14, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 232-6, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 232
DEP Docket No. E2, Sub 1300
Item No. 232-6
Page 1 of 1

Request:

6. In response to PS DR 155-12, Transmission, similar to the previous question directly above, the Company answered the questions uniquely different; however, the Company did not answer sub part e.i.: "List the total amount of work expected to be completed by internal versus external resources." The Company's response is that "if internal crews are maxed out…". Please answer the following questions:
   a. Using the Company's methodology stated in response to PS DR 155-29 (c-e), list by rate year or each month of the rate year if a monthly amount is more aligned with staffing and budgeting (the Company can choose the monthly or rate year metric) the resources needed from both internal and external staffing sources to implement the MYRP.
      i. For internal staffing, list the Company's 2022 internal staffing (full time equivalent employees or any other metric that the Company believes is accurate or a reasonable metric) that could complete MYRP tasks or MYRP-like tasks.
      ii. List the "gap" of resources needed to complete all of the Company's proposed projects in the MYRP.

Response:

a. Transmission cannot apply the methodology described in response 155-29 (c-e) due to the nature of the work being distinctly different than distribution type work. Transmission projects are typically multiyear, complex, involving multiple disciplines (electrical, civil, mechanical) and therefore resource needs are determined by each individual scope of work as compared to the Distribution method that utilizes the target budget numbers and average cost per resource.

i. Duke Energy staffing as of 12/31/2022

- Project Managmenet - 33
- DEP Energy Control Center (ECC) - 33
- Trans Construction & Maintenance (C&M) - 200
- Trans Engineering - 83
- Trans Veg Management - 9

ii. As part of the normal Transmission resourcing strategy, external resource needs across all departments are determined based on the individual scope of each project. As described in 155-12, we have Master Service Agreements with external contractors that allow us operational flexibility to quickly ramp up and down to meet the variations in resource requirements based on scope of work, to deliver the best possible value to customers.

MYRP Project	Interdependent "Routine Work" item*	Estimated Inservice Date
DEP LMR	Towers Shelters Power Supplies - Harris MW	2023-Q4
DEP LMR	Towers Shelters Power Supplies - Ruby Radio Bldg	2024-Q3
DEP LMR	Towers Shelters Power Supplies - Littleton Radio Site	2024-Q3
DEP LMR	Towers Shelters Power Supplies - Rocky Mt MW (Tower Site)	2025-Q2
DEP LMR	Towers Shelters Power Supplies - Flat Top	2026-Q3

Area Capacity Upgrade - Retail Project	Task/Location	Retail ISD	Related System Capacity Project	System ISD
Triangle South - 270 Area Capacity Upgrade Project	Camp Kanata 230kV	6/1/2024	Area Capacity Upgrade - Camp Kanata 230kV	6/1/2024
Triangle South - 271 Area Capacity Upgrade Project	CARALEIGH 230KV	6/1/2024	Substation & Line - Caraleigh 230kV	2/24/2026
Triangle South - 271 Area Capacity Upgrade Project	Cary Triangle Expressway 230kV	5/1/2024	Area Capacity Upgrade - Cary Triangle Expressway 230kV	5/1/2024
Coastal - 282 Area Capacity Upgrade Project	Castle Hayne 230kV #2 – Add FCB	6/1/2024	Substation & Line - Castle Hayne 230kV	5/7/2024
Triangle South - 271 Area Capacity Upgrade Project	FUQUAY WADE NASH ROAD 115KV	5/1/2024	Substation & Line - Fuquay Wade Nash Road 115kV	1/8/2024
Triangle South - 271 Area Capacity Upgrade Project	MORRISVILLE 230KV	11/1/2023	Substation & Line - Morrisville 230kV	9/17/2024
Triangle South - 271 Area Capacity Upgrade Project	NEW HILL 230KV	11/1/2024	Area Capacity Upgrade - NEW HILL 230KV	11/1/2024
Triangle South - 272 Area Capacity Upgrade Project	Pittsboro Hanks Chapel 230kV	8/1/2024	Substation & Line - Pittsboro 230kV	8/11/2024
Triangle South - 270 Area Capacity Upgrade Project	Raleigh Atlantic Avenue 115kV	5/1/2025	Area Capacity Upgrade - Raleigh Atlantic Avenue 115kV	5/1/2025
Mountains - 231 Area Capacity Upgrade Project	Reems Creek 115kV	3/1/2024	Area Capacity Upgrade - Reems Creek 115kV	3/4/2024
Triangle North - 262 Area Capacity Upgrade Project	Shotwell 230kV	11/1/2025	Substation & Line - Archer Lodge 230kV	7/26/2026
Triangle South - 272 Area Capacity Upgrade Project	SOUTHERN PINES CENTER PARK 115KV	3/1/2024	Substation & Line - Southern Pines Center Park 115kV	5/1/2024
Triangle South - 271 Area Capacity Upgrade Project	Wake Tech 230kV	5/1/2024	Area Capacity Upgrade - Wake Tech 230kV	5/1/2024
Coastal - 282 Area Capacity Upgrade Project	Wilmington 421 230 kV	12/1/2024	Area Capacity Upgrade - Wilmington 421 230 kV	12/1/2024
Coastal - 282 Area Capacity Upgrade Project	Wilmington Sunset Park 115kV #2	3/5/2024	Area Capacity Upgrade - Wilmington Sunset Park 115kV #2	3/5/2024
Triangle North - 262 Area Capacity Upgrade Project	YOUNGSVILLE 115KV	5/28/2024	Substation & Line - Youngsville 115kV	9/27/2024

SOG Team	MYRP Project	Interdependent Substations for SOG	Estimated Substation ISD
52	ASHEBORO NORTH 115KV	ASHEBORO EAST 115KV	3/10/2028
52	ASHEBORO NORTH 115KV	ASHEBORO NORTH 115KV	4/10/2024
65	SPRING HOPE 115KV	SPRING HOPE 115KV	1/7/2024
65	SPRING HOPE 115KV	STALLINGS CROSSROADS 115KV	2/25/2027
146	CLINTON NORTH 115KV	CLINTON NORTH 115KV	5/13/2025
146	NEWTON GROVE 230KV	NEWTON GROVE 230KV	3/8/2025
149	BENSON 230KV	BENSON 230KV	1/16/2025
149	BENSON 230KV	BUIES CREEK 230KV	2/16/2027
226	METHOD 230KV	METHOD 230KV	12/20/2023
226	METHOD 230KV	MORDECAI 115KV	1/1/2024
226	METHOD 230KV	RALEIGH 115KV	12/26/2023
248	CLEVELAND MATTHEWS ROAD 230KV	CLAYTON 115KV	7/1/2025
248	CLEVELAND MATTHEWS ROAD 230KV	CLEVELAND MATTHEWS ROAD 230KV	2/3/2025
249	CLEVELAND MATTHEWS ROAD 230KV	CLEVELAND MATTHEWS ROAD 230KV	2/3/2025
249	CLEVELAND MATTHEWS ROAD 230KV	EDMONDSON 230KV	1/12/2024
255	ASHEBORO SOUTH 115KV	ASHEBORO EAST 115KV	3/10/2028
255	ASHEBORO SOUTH 115KV	ASHEBORO SOUTH 115KV	4/30/2025
278	GOLDSBORO CITY 115KV	GOLDSBORO CITY 115KV	8/14/2024
278	GOLDSBORO CITY 115KV	SEYMOUR JOHNSON 115KV	12/29/2024
282	ROCKY MOUNT 230KV	ELM CITY 115KV	1/30/2026
282	ROCKY MOUNT 230KV	ROCKY MOUNT 230KV	4/17/2025
301	WARSAW 230KV	CLINTON FERRELL ST. 115KV	12/25/2023
301	WARSAW 230KV	WARSAW 230KV	3/7/2025
304	HOPE MILLS CHURCH ST. 115KV	HOPE MILLS CHURCH ST. 115KV	2/18/2025
304	HOPE MILLS CHURCH ST. 115KV	SHANNON 115KV	TBD
306	JONESBORO 230KV	BEAR BRANCH 230KV	TBD
306	JONESBORO 230KV	JONESBORO 230KV	8/21/2025
307	CHADBOURN 115KV	CHADBOURN 115KV	3/7/2025
307	CHADBOURN 115KV	FAIR BLUFF 115KV	1/4/2025
314	ROSEBORO 115KV	ROSEBORO 115KV	7/23/2024
314	ROSEBORO 115KV	VANDER 115KV	2/16/2029
314	SANFORD GARDEN ST 230KV	SANFORD GARDEN ST 230KV	9/29/2025
330	BENSON 230KV	BENSON 230KV	1/16/2025
330	FOUR OAKS 230KV	FOUR OAKS 230KV	12/24/2023
331	LAUREL HILL 230KV	LAUREL HILL 230KV	1/31/2024
331	LAUREL HILL 230KV	LAURINBURG CITY 230KV	2/17/2026
334	BAHAMA 230KV	BAHAMA 230KV	1/20/2024
334	BAHAMA 230KV	ROXBORO SOUTH 230KV	2/6/2029
337	WRIGHTSVILLE BEACH 230KV	WILMINGTON OGDEN 230KV	6/13/2024
337	WRIGHTSVILLE BEACH 230KV	WRIGHTSVILLE BEACH 230KV	7/28/2024
341	WEATHERSPOON 230KV	FAIRMONT 115KV	3/11/2028
341	WEATHERSPOON 230KV	WEATHERSPOON 230KV	8/26/2025
342	BLADENBORO 115KV	BLADENBORO 115KV	2/22/2025
342	BLADENBORO 115KV	CLARKTON 115KV	TBD
346	JONESBORO 230KV	BEAR BRANCH 230KV	TBD
346	JONESBORO 230KV	JONESBORO 230KV	8/21/2025

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 232

Docket No. E-2, Sub 1300

Date of Request: February 28, 2023
Date of Response: March 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 232-7, was provided to me by the following individual(s): Linda Costantino, Lead Planning and Regulatory Support Specialist, and provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 232
DEP Docket No. E2, Sub 1300
Item No. 232-7
Page 1 of 3

Request:

7. In response to PS DR 155-32, Distribution, the Company did not answer the full question. The question asked for each "MYRP project" whereas the Company answered the question at a program level. While the Public Staff found the Company's response beneficial, please answer the question per MYRP project, as originally asked, on the dependencies that exist for: Substation and Line, Retail and System Capacity, Land Mobile Radio, ADMS.

Note: The Public Staff is trying to evaluate the timing and risk dependencies of Duke's proposed MYRP project plan. With the information to date, the Public Staff cannot determine the dependencies and cascading impacts of projects, or if the MYRP project timing is accurate for Rate Year purposes.

Response:

Substation and Line
Dependencies (Yes/No) Yes
Dependency description: The SOG work consists of three (3) major components: SOG reduces circuits into switchable segments to minimize the number of customers affected by sustained outages, expands the capacity to support an integrated grid, and ensures the necessary connectivity to allow for rerouting options.

For some SOG team installations that cross substations, coordinated work between substations is required to complete the back-feed capability for all circuits in the team. All SOG work associated with completing a self-healing team within or between substations will be completed and charged to the substation being optimized, notwithstanding the optimization schedules of the other substations. Please see attachment DEP PS DR 232-7 Substation and Line.docx for table of substation coordination required for self-healing team installations currently identified in the MYRP.

Coordination between substations for the remaining MYRP planned self-healing teams will be identified during the development phase that takes place prior to Initiate gate approval.

Retail and System Capacity
Dependencies (Yes/No) Yes
Dependency description: The retail and system capacity work are interdependent. The retail projects provide needed substation capacity, and the related system projects are needed to transfer power from the substation to the customer load centers.

System and retail capacity projects can be executed simultaneously, and the in-service date of the system capacity project is dependent on the completion of the retail portion of the project. Some of the system capacity projects will be executed within MYRP Substation & Line projects, and some will be executed as Area Capacity Upgrade projects. Please see attachment DEP PS DR 232-7 System and Retail Capacity.docx for table of the Area Capacity Upgrade Retail projects with their associated system capacity projects, either in Area Capacity Upgrade System or Substation & Line.

North Carolina Public Staff
Data Request No. 232
DEP Docket No. E2, Sub 1300
Item No. 232-7
Page 2 of 3

Please note that the Castle Hayne and Fuquay Wade Nash Road project in-service dates will be further coordinated during execution.

Land Mobile Radio

Dependencies (Yes/No) Yes
Dependency description: Land Mobile Radio (LMR) is highly reliant on towers as an integral part of the overall wide area network to provide the coverage required for communications between the dispatchers and the field worker's truck radios. Tower site construction delays could result in gaps in the coverage within the geographic vicinity of the tower.

DEP LMR is a formal, gated "Project" while the dependency is on "Routine Work" items under the Towers Shelters and Power Supplies (TSPS) workstream. Please see attachment DEP PS DR 232-7 LMR.docx for a table documentation of dependency.

ADMS

Dependencies (Yes/No) Yes
Dependency description: The Advanced DMS Program impacts the systems used in all of Duke Energy's Distribution Control Centers (DCC). The program's vision is to enable Customer Delivery to develop, deploy, upgrade, and consolidate the Distribution Management System (DMS), Supervisory Control and Data Acquisition (SCADA) systems, and Outage Management Systems (OMS) across the enterprise, using a single vendor for a unified platform.

The ADMS program used the following deployment approach for the systems:
All Duke jurisdictions transitioned to GE's SCADA product by end of 2019.
Then, all jurisdictions transitioned to GE's DMS product in 2020.
In 2020, the ADMS program began deploying OMS. Work to deploy OMS in the DEP jurisdiction is expected to begin in 2023.
The DER Dispatch project will be implemented by jurisdiction following EMS version 3.3 and ADMS version 3.10+ implementation in each jurisdiction.

Although each of the 3 GE Products DMS/SCADA/OMS, are independent Duke software assets, the projects are dependent upon each other for versioning and compatibility. OMS needs to be on the same version of DMS so, the projects need to go live around the same time.

When we perform upgrades to one system, typically we upgrade the other, to match the newer version for functionality purposes. This means that when we deploy GE OMS to DEP, we will synchronize the upgrades of DEP's DMS and SCADA systems, to ensure delivery of full functionality and system compatibility. CLFISR can work independent of a DMS upgrade, however the CLFISR project does depend upon the DMS upgrade to unlock full capabilities. The DER Dispatch project is dependent on EMS version 3.3 and ADMS version 3.10+ to deliver the required functionality defined in the project's defined Minimum Viable Product (MVP).

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 232

Docket No. E-2, Sub 1300

Date of Request: February 28, 2023
Date of Response: March 14, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 232-8, was provided to me by the following individual(s): Alisa Ewald, Developmental Assignment, and provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 232
DEP Docket No. E2, Sub 1300
Item No. 232-8
Page 1 of 2

Request:

8. In response to PS DR 155-15, Transmission, similar to the previous question directly above for distribution, the Company answered the question "At this time, DEP has not identified any MYRP projects that have dependencies between rate years." Please answer the following questions related to the Company's response that are fully responsive to the original question:
   a. Does the Company mean by "at this time" that there is no dependency analysis, work scheduling, planning, or MYRP project implementation that has been completed, therefore there is nothing to provide? Or, does the Company's response mean that the Company's transmission MYRP project plan has been evaluated for scheduling dependencies, outage work, outage scheduling, etc., and the Company's plan can be implemented without concern for scheduling impacts from other MYRP projects?
   b. Please explain why distribution has identified dependencies but transmission has not given the structured nature and timing requirements of such large scale and long duration time work activities.
   c. Please explain how the Company has planned, and included as part of the listed costs in the MYRP project, to leverage project efficiencies, economies of scale, and mitigating project risk exception
   d. The Company also listed "work plans" in its response. Please clarify what constitutes a "work plan" as it relates to MYRP transmission projects and when a work plan(s) will be completed.
   e. The Company also listed "portfolio level" in its response. Please clarify what constitutes "portfolio level" as it relates to MYRP transmission projects and when this evaluation will be completed for each MYRP project.

Response:

a. In response to PS DR 155-15, Transmission meant that the Transmission MYRP project plan has been evaluated for scheduling dependencies, outage work, etc and does not see any concern dependencies that would preclude us from executing the projects in the manner laid out in the MYRP.

b. When Transmission projects go through the development stage, we use subject matter experts to align work at the same location to happen in parallel. This minimizes, and often eliminates, the number of dependencies between projects. After the project location is scoped, the project is submitted to the transmission outage coordination team who slots the project's outage in context of the expected outage availability with projected system loads and other planned work in a further effort to minimize project dependencies. For example, some project locations may need a mobile transformer to maintain continuity of service to customers served from that substation. The project planners, during constructability reviews, make sure the mobile transformer is available and installed prior to offloading the station for the construction work.

c. The same process is used for item b.

North Carolina Public Staff
Data Request No. 232
DEP Docket No. E2, Sub 1300
Item No. 232-8
Page 2 of 2

d. The term "work plans" in response to PS DR 155-15, Transmission refers to the scheduling of work for each project location. These work plans are created by our Work Management Group, ninety days after the engineering release. These work plans provide a high level, milestone schedule for the project (i.e. mobilization date, material delivery date, clearance windows, completion date, etc.). These work plans are provided to our contractors who, in turn, develop their own detailed schedules based on the milestone dates we provide.

e. The term "portfolio level" in response to PS DR 155-15, Transmission relates to all the work being managed both MYRP and non-MYRP. These portfolio level reviews are ongoing coordination as part of our project planning.

	Line Headcount	**Distribution CapEx Spend**
2021	3,982 (Actual Jan 2021)	$1.5B (Actual)
2022	5,261 (Actual Dec 2022)	$2.1B (Actual)
2023	5,423 (Forecasted Need) / 5,311 (Actual Jan 2023)	$2.4B (Forecast)

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 232

Docket No. E-2, Sub 1300

Date of Request: February 28, 2023
Date of Response: March 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 232-9, was provided to me by the following individual(s): Linda Costantino, Lead Planning and Regulatory Support Specialist, and provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 232
DEP Docket No. E2, Sub 1300
Item No. 232-9
Page 1 of 1

Request:

9. In response to PS DR 155-34, the Company discusses the increase from 2023 to 2024 forecasted spend; however, the Public Staff has not audited the 2023 projects from a historic rate case review.
   a. Please provide context as to how the distribution labor and forecast spend have increased from 2021 and 2022 to 2023.
   b. Discuss the actions being taken by the Company to staff or staff augment up to 2021 and 2022 project work as well as routine work to 2023 levels.

Response:

a. Please see attachment DEP PS DR 232-9 Headcount to Capex.docx for a table showing a summary of the requested information. Please note this is total Carolinas, including DEP and DEC for North and South Carolina. This information is the basis for resource forecasting.

The Company ramped up resources throughout 2021 and 2022 on a glidepath to reach the 2023 target.

b. As stated in response to DEP PS DR 155-20, Duke Energy employs multiple strategies to ensure the resources needed are secured in a timely manner. Examples of these strategies include,but are not limited to: contracts for Distribution Line Construction, Enterprise Engineering of Choice contracts (EEOC), contracts for specific workstreams (i.e., Pole Inspection, Flagging, Locates, Damage Assessment, etc.), Engineering turnkey contracts (EPC), Regional and Niche contracts for Distribution Line and Engineer/Construct contracts. Also, Duke Energy evaluates resourcing strategies on an ongoing basis as work progresses and employs strategies like shifting resources to areas of need and flexing work schedules.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 232

Docket No. E-2, Sub 1300

Date of Request: February 28, 2023
Date of Response: March 15, 2023

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 232-10, was provided to me by the following individual(s): Kathryn Taylor, Rates and Regulatory Manager, and provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 232
DEP Docket No. E2, Sub 1300
Item No. 232-10

Request:

10. Please demonstrate for each MYRP project that Duke's proposed timing of project completion is reasonable and ensures a high level of certainty that the project can be completed and can be completed in the time period Duke listed.

    Note: The use of "reasonable" and "high level of certainty" are generic terms, which imply a level of subjectivity. To date, the Public Staff has not been able to determine how Duke has planned for timing, labor and staffing for each project, and each project is part of the MYRP plan and each project is part of the revenue requirements and rates ratepayers will be paying if the Commission approves Duke's PBR application. This is the last discovery prior to the Public Staff filing initial testimony for Duke to demonstrate the following concepts:

    A. Can the projects be completed in the time period (month and year) in which Duke proposed and how did Duke make such a determination? Notably, Transmission, Distribution, Other and General category projects should be the focus of this topic. The Company has resolved Nuclear, Coal, and Natural gas project timelines.
    B. List project dependencies, which would support the timing and implementation of specific projects in Duke's proposal. This would also ensure there the project would be used and useful and providing benefit and service to ratepayers for when it is projected to be in service.
    C. The responses should be for each business unit/jurisdiction, and a general narrative is not sufficient to support the information being requested in this discovery or prior discoveries.
    D. Demonstrate how normal business work, projects, and work not in the MYRP, are also being considered with MYRP project timing, planning, and resource loading.

Response:

Transmission and Distribution

A and D. Yes. As the responses to PS DR 155 and 232-5 through 9 highlight, the Transmission and Distribution functions do not have consistent methodologies for staffing and assessing resource needs but each function adheres to practices that have been employed for years and are consistent with prudent utility practice. There is no evidence that the Company has, or will have, an issue obtaining sufficient labor resources and the Company is confident in its ability to execute the T&D MYRP projects in the time period proposed.

The Transmission and Distribution projects within the MYRP are types of projects the Company has completed for years and as such, the T&D functions have experience in executing these types of projects and is capable of doing so in conjunction with non-MYRP work. The Company employs multiple strategies (as explained in responses to PS DR 155) to ensure the resources needed are secured in a timely manner and that projects are completed on projected timelines. This holds true for MYRP and non-MYRP work alike. For example, strategies employed by the Transmission function include: creating detailed "look ahead" workplans at 6-month intervals (taking into consideration outage constraints, summer and winter peaks, and generation outages); evaluating resourcing strategies on an ongoing basis as work progresses and employing strategies like shifting resources to areas of need and flexing work schedules, reserving manufacturing "slots" with suppliers for project components, and reserving/ordering certain materials from suppliers (i.e., breakers, transformers, regulators, relay panels, control houses) during the conceptual design stage.

B. Please refer to DEP's responses to PS DR 232-7 and -8.

Solar:

D. DEP's estimated timing of project completion for each MYRP solar project is reasonable and ensures a high level of certainty that DEP will complete the projects within the established time frame. The data points discussed below support the reasonableness of DEP's proposed timeline for each project.

Asheville Solar Project:

As discussed in DEP's response to PS 10-1(j), the Asheville Solar project can be placed in-service by September 2025. Importantly, DEP filed a CPCN application for the project in January 2023 and hearings are scheduled to take place in May 2023. DEP expects that Buncombe County will approve the required special use permit in April 2023. Upon CPCN approval, DEP plans to secure major equipment (modules and generator step-up transformer) in Q3 and Q4 2023. Following a competitive EPC RFP process, DEP expects to have an executed contract with a selected EPC partner by the end of 2023 or early 2024.

In addition, the project has more than a full calendar year to design and obtain required construction permits prior to site mobilization in early 2025. For a project of this size, DEP expects that construction will take approximately nine months—this construction timeline comports with the September 2025 in-service date target that DEP has proposed for the Asheville Solar Project. Furthermore, the executed interconnection agreement for the Asheville Solar Project supports the target in-service date.
Each data point above supports the reasonableness of DEP's proposed timing for project completion.

2026 Solar Investment Project (Selected Solar Project):

DEP plans on filing a CPCN transfer request by mid-year 2023 and anticipates that the Commission will conduct hearings and render a decision by the end of 2023. DEP is in the process of securing major equipment (modules and generator step-up transformer) and anticipates issuing purchase orders in the coming months. Note that the project has already secured the required county zoning approval.
DEP anticipates having an executed contract with an EPC partner by Q3/Q4 2023. The project has more than a full calendar year to design and obtain construction permits prior a site mobilization in Q3 2024. For a project of this size, DEP expects that construction will take approximately twelve months—this construction timeline comports with the

North Carolina Public Staff
Data Request No. 232
DEP Docket No. E2, Sub 1300
Item No. 232-10

September 2025 in-service date target that DEP has proposed for the 2026 Solar Investment.

Storage:
D. DEP's estimated timing of project completion for each MYRP storage project is reasonable and ensures a high level of certainty that DEP will complete the projects within the established time frame. The below factors inform this determination.

As of the time of this response, for those projects for which completion of network upgrades is required to achieve in-service MYRP projects all either have an executed Interconnection Agreement in-hand or have made significant progress through one of various interconnection study pathways.

For some MYRP storage projects, DEP is in the process of securing long lead time equipment (including inverters, switchgear, and transformers) and anticipates issuing purchase orders in the coming weeks.

For all storage MYRP projects, DEP anticipates having an executed contract with an EPC partner 12-18 months prior to in-service date during which time detailed design, permitting, and zoning will take place. Mobilization for site construction activities is expected 8-10 months prior to in-service date.

While the portfolio of projects DEP proposes includes the Company's largest-ever battery storage project, the size of battery projects across the utility industry have continued to rise in recent years meaning that DEP's proposed projects are well within the capacity of construction partners to produce with their existing processes and organizations.

Finally, DEP has increased confidence in achieving the storage MYRP timelines due to its efforts to levelize the workload on engineering, procurement, project management, and environmental/Health/Safety and EPC-partner organizations across the execution period (roughly mid-2023 through March 2025) by staggering the in-service dates of its pipeline of projects. This steady pace of execution fosters continuity of project teams from one energy storage asset to the next and allows for lessons learned from prior projects to inform future work.

CONFIDENTIAL

Docket No. E-2, Sub 1300

Public Staff Confidential Metz Exhibit 2