



**ADMINISTRATOR'S REPORT**  
**Kevin Bronson**  
Office of the City Administrator  
Westminster, South Carolina

August 22, 2025

### **GENERAL INFORMATION**

#### **Downtown Streetscape Project**

Bids for Phase I of the Westminster Downtown Streetscape Project was published on Friday, August 13. Bids will be due on September 22, 2025. The solicitation can be found at:  
[www.westminstersc.org/departments/administration/#bids](http://www.westminstersc.org/departments/administration/#bids).

#### **This Week in Rec: An Update from Recreation Director Herb Poole**

- The Football Apple Bowl was a huge success. Westminster Recreation hosted Pendleton and Walhalla at Owens Stadium.
- Soccer, baseball, softball, and volleyball game schedules will be available in the coming two weeks.
- We thank the City Council and County Council for celebrating our 10u softball state championship with us.
- Football schedules can be found on the Recreation Facebook Page
- We are implementing card readers for the recreation department. Participants and spectators will have the ability to make concessions and admission payments with credit/debit cards.

#### **Assistant Recreation Director**

In the FY 2026 Budget, City Council authorized the creation of an Assistant Recreation Director position. The job has been posted on the City and MASC Websites. The job posting can be found at  
<https://westminstersc.org/careers/>.

#### **Recreation Card Readers for Concessions and Admissions Payments**

Westminster Recreation has received and installed some of its card readers and will begin limitedly accepting debit and credit cards while learning and troubleshooting the new payment system. Card readers will be implemented across facilities for concessions and admissions over the coming weeks. The Recreation Department will continue to use Stripe (its current platform) for online registration.

#### **Horton Outdoor Recreational Area**

AMW General Contractors began preparing the forms for the concession building this week. Next week the pad for the building is planned to be poured.

Field construction crews continued to work on field components. The outfields have been holding water due to the amount of rain the last couple of weeks. A team of Mammoth engineers and the Mammoth

owner visited the site this week and decided to re-engineer the drain system in the outfields so they will drain better. The rain runoff was not filtering down to the so-called sock drains due to the compaction of the clay ground. The new system will be a trench filled with rock and then covered by the topsoil. Crews began work immediately after the decision was made to reengineer, one fields is nearly complete with the others to follow this weekend. Next week the irrigation contractor is scheduled to be back on site to continue with its work. Construction of two of the light poles was completed this week, the others to follow as filed conditions allow the lighting contractor to work.

### **Coopers Mill Phase II**

HDH Construction has completed the sewer main and service connections. HDH began installing the main water line.

### **SCIIP Sewer Improvements Phase I**

Tugaloo/McClam has completed Spring St. and are mobbing materials and equipment to begin on Crooked Street.

### **SCIIP Sewer Improvements Phase II**

LW Incorporated is the contractor for the second phase of the SCIIP improvements. Below is a timeline and attached is a project map.

The dates and estimated times to complete the project within the 285 days in the contract. This timeline was the basis for the negotiated bid. It is expected that amendments to this estimate will change as the project progresses.

- 8/20 - preliminary sawcut work began
- 8/21 - pipe and fittings delivered
- 8/27 - scheduled MH delivery
- 8/27 - begin construction on Line "A"
- Traffic Control Structures received and placed by the first week in September. Work on Line C to begin once these are in place and Line A is complete.
- LW anticipates completing manhole-to-manhole sections on an approximate three-week cycle, recognizing that actual durations may vary due to differing line lengths. Based on this projection, line work is expected to be substantially complete by early to mid-May, with overlays and punchout activities concluded by the end of the month.

### **Heirloom Farms**

Water services have been moved to the new water main on Seed Farm Road and tap installation has begun. Sewer is complete.

### **2025 Municipal Election Information**

For the Special Election to fill the unexpired term for the City Council seat recently vacated the Oconee County Voter Registration and Elections Office provided the following:

- Candidate Filing Opens - Friday, August 29 @ Noon

- Candidate Filing Closes - Monday, September 8 @ Noon\*  
(\*Please note the office will be closed on Monday, September 1 in observance of Labor Day)

The Special Election will be added to the November 2025 Election.

### Westminster Planning Commission

The Westminster Planning Commission met on Monday, August 18, 2025 to discuss the proposed ordinance to provide exceptions to the blanket ban on the discharge of firearms. After deliberation, the Commission made several changes to the proposed ordinance and requested that the new language be presented again to the Planning Commission before they make a recommendation to City Council. The updated Ordinance will be considered again by the Planning Commission at the September 15 meeting.

### OJRSA

The OJRSA Ad Hoc Reconstitution Committee met Thursday, August 14, 2025, at 2:00 pm; the draft meeting minutes are attached. The meeting may be viewed on YouTube at <https://www.youtube.com/watch?v=oiOJKM4GP60>.

The OJRSA Operations and Planning Committee met on Wednesday, August 20, 2025, at OJRSA. The draft meeting minutes are attached.

The OJRSA Finance and Administration Committee will meet on Tuesday, August 26, 2025 at 9:00am at OJRSA.

### PMPA

The PMPA Board met on Thursday, August 21, 2025. The agenda is attached.

### **Duke Energy Carolina and Duke Energy Progress Merger Request**

On Thursday, August 14<sup>th</sup>, Duke Energy asked state and federal regulators to allow it to combine Duke Energy Carolinas and Duke Energy Progress. Duke would like this to be effective by January 2027. Duke's justification for the technical merger is better efficiency and lower cost to meet the growing needs in the Carolinas. They estimate about \$1 billion in savings through 2038. The merger would need permission from the SC Public Service Commission, NC Utilities Commission, and FERC. The full filing is attached at the end of the Administrator Report, a synopsis is available at the link below. <https://www.publicpower.org/periodical/article/duke-energy-seeks-approvals-combine-its-two-electric-utilities-carolinas>

### **Electric System Transformer Supply Chain**

A recent report by energy research and consultancy firm Wood Mackenzie states that U.S. demand for transformers has surged sharply since 2019—power transformers by 116% and distribution transformers by 41%—driven by rising electricity use, clean energy projects, and aging infrastructure. Supply has not kept pace, creating shortages projected to reach 30% for power transformers and 10% for distribution transformers in 2025. Imports will make up 80% and 50% of supply (in 2025), respectively, leading to higher costs, longer lead times, and project delays. Both domestic and imports will be subject to higher costs due to a combination of tariffs. Most notable is the 50% tariff on imported copper that went into effect August 1<sup>st</sup>. The tariff applies to semi-finished products like pipe and wire but excludes input materials like ore, cathodes, anodes, and copper scrap. Alongside the tariff

under the Defense Production Act, the administration is requiring 25% of domestically produced high-quality copper scrap to be sold within the USA. The \$1.8 billion announced domestic OEM expansion since 2023 will help ease but not meet the expected increasing demand. An analyst with the consultancy firm believes “The convergence of accelerating electricity demand, aging infrastructure and supply chain vulnerabilities has created constraints that will persist well into the 2030s”. He believes all of this will be the new normal without decisive intervention.

<https://www.publicpower.org/periodical/article/power-transformers-and-distribution-transformers-will-face-supply-deficits-30-and-10-2025-report>

**PLEASE MARK YOUR CALENDARS**

August 26, 2025 at 9:00 am OJRSA Finance & Administration Committee at OJRSA

*September 1, 2025 City Offices Closed to Observe Labor Day*

September 8, 2025 at 4:00 pm OJRSA Board Meeting at OJRSA

**September 9, 2025 at 6:00 pm City Council Meeting at the Westminster Fire Department**

September 11, 2025 at 9:00am OJRSA Ad Hoc Reconstitution Committee at OJRSA

September 15, 2025 at 6:00 pm Westminster Planning Commission Meeting at City Hall

September 18, 2025 at 8:30 am OJRSA Operations & Planning Committee at OJRSA

September 18, 2025 at 10:00 am PMPA Board Meeting at PMPA

**City Council Meeting Schedule:**

January 14, 2025		6:00 PM	City Council Meeting
February 11, 2025	4:00 PM	6:00 PM	Budget Workshop/City Council Meeting
March 11, 2025	4:00 PM	6:00 PM	Budget Workshop/City Council Meeting
April 8, 2025	4:00 PM	6:00 PM	Budget Workshop/City Council Meeting
April 29, 2025	4:00 PM		Budget Workshop
May 13, 2025		6:00 PM	City Council Meeting
June 17, 2025		6:00 PM	City Council Meeting
July 8, 2025		6:00 PM	City Council Meeting
August 12, 2025		6:00 PM	City Council Meeting
September 9, 2025		6:00 PM	City Council Meeting
October 14, 2025		6:00 PM	City Council Meeting
November 18, 2025		6:00 PM	City Council Meeting
December 9, 2025		6:00 PM	City Council Meeting

**Special Events Calendar**

**South Carolina Apple Festival-** September 5-6, 2025 on Main Street Westminster

*The South Carolina Apple Festival Committee Hosts the Westminster Apple Festival on Main Street.*

**150<sup>th</sup> Birthday Tea Party-** October 4, 2025 at 2:00pm at the Martin House

*Join the Lazy Daisy Garden Club for a Tea Party Celebrating Westminster’s 150<sup>th</sup> Birthday. Tickets will be \$10 per person. All proceeds will go to support scholarships for West-Oak Highschool Students. Tickets must be reserved by September 18 and can be purchased at <https://www.zeffy.com/en-US/ticketing/westminster-150th-birthday-tea-party>. A flyer is attached.*

**South Carolina Bigfoot Festival-** October 10-11, 2025 on Main Street Westminster

*The South Carolina Bigfoot Festival Committee Hosts the Westminster Bigfoot Festival on Main Street.*

**Boo on Main!**- October 31, 2025 on Main Street Westminster

*The City's annual Boo on Main! Features a festival style trunk or treat for Westminster Children on Halloween Night.*

**Westminster Arbor Day Celebration** – December 5, 2025 time and place TBD.

**Westminster Christmas Parade and Tree Lighting-** December 5, 2025 on Main Street and Retreat Street Park

**Job Title:** Assistant Recreation Director

**Department:** Parks & Recreation

**Location:** City of Westminster, SC

**Reports To:** Recreation Director

**FLSA Status:** Non-Exempt / Full-Time

**Salary Range:** \$42,000-\$55,000 (depending on qualifications and experience)

### **Position Summary:**

The City of Westminster is seeking a dedicated, proactive, and knowledgeable **Assistant Recreation Director** to support the development, implementation, and maintenance of recreation programs, athletic leagues, special events, and park operations. A key focus of this role will be the **oversight and management of turf maintenance and field conditions** at city recreation facilities to ensure safe, attractive, and playable surfaces for all users.

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### **Essential Duties and Responsibilities:**

- Assist in planning, coordinating, and supervising youth and adult recreational programs, athletics, and events
  - Manage the maintenance and scheduling of athletic fields, including but not limited to turf maintenance, irrigation monitoring, and field preparation for games and practices
  - Develop and implement turf management plans, including mowing schedules, aeration, fertilization, weed control, and pest management.
  - Supervise part-time and seasonal staff; assist with staff scheduling training, and performance monitoring
  - Serve as acting Recreation Director in their absence
  - Collaborate with local sports leagues and community groups to ensure efficient use of recreational spaces
  - Ensure compliance with safety regulations and departmental standards across all recreation areas
  - Assist in budget preparation and purchasing for recreation supplies, field maintenance materials, and equipment
  - Respond to citizen inquiries and concerns in a professional and timely manner
  - Assist with the planning and execution of city-wide special events and sponsorship activities
  - Maintain accurate records of program participation, maintenance logs, and field conditions
  - Operate and maintain various types of field and turf maintenance equipment
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**Qualifications:**

**Education and Experience:**

- Associate or Bachelor's degree in Recreation, Turfgrass Management, Horticulture, Sports Management or related field preferred
- Minimum of 3 years of experience in parks and recreation, athletic field maintenance, or turfgrass management
- Supervisory experience is strongly preferred

**Certifications:**

- Certified Parks and Recreation Professional (CPRP) or equivalent preferred
  - Pesticide Applicator License (or ability to obtain within 12 months of hire) is a plus
  - Valid South Carolina Driver's License required
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**Knowledge, Skills, and Abilities:**

- Strong knowledge of athletic field maintenance techniques and turf management practices
  - Experience operating turf care equipment such as aerators, mowers, sprayers, and line markers
  - Ability to communicate effectively with the public, staff, and contractors
  - Excellent organizational and time management skills
  - Proficiency with Microsoft Office Suite and recreation management software is a plus
  - In addition to normal working hours, the ability to work evenings, weekends, and holidays as needed
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**Working Conditions:**

- Work is performed indoors and outdoors in all weather conditions
  - Must be able to lift and carry up to 50 pounds
  - Exposure to chemicals used in turf maintenance may occur with appropriate safety measures in place
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**Equal Opportunity Employer Statement:**

The City of Westminster is an equal opportunity employer and does not discriminate on the basis of race, color, religion, sex, and national origin, age, disability, or genetic information in employment or the provision of services.

Please email resumes to the Recreation Director, Herb Poole at [hpoole@westminstersc.org](mailto:hpoole@westminstersc.org)

## PART 2:

- About 2-3 Months
- Approx. 1013' of 8" Line
- Depths range from 6 to 10.5 feet
- New line to replace old line
- Significant Impact to Traffic (will coordinate with SDOC, Law Enforcement, and Emergency Services)
- All work within right-of-way and Oak St
- Will impact HWY 24 to Sandifer Funeral Home

## PART 1:

- About 1-2 Months
- Approx. 529' of 8" Line
- Depths range from 6 to 10 feet
- New line to replace old line
- Some minor impacts to Oak Street
- All work within right-of-way and Oak St.

## General Notes

- All locations and times are approximate. Delays are possible.
- Grant funded through SCIIP: \$2,094,690
- Traffic impacts will be minimized wherever possible
- Work to be completed by LW, Inc.



# Oconee Joint Regional Sewer Authority

623 Return Church Road  
Seneca, South Carolina 29678  
Phone (864) 972-3900  
www.ojrja.org

## OCONEE JOINT REGIONAL SEWER AUTHORITY Ad-Hoc Reconstitution Committee and Executive Committee August 14, 2025

The Ad-Hoc Reconstitution Committee and Executive Committee meeting was held at the Coneross Creek Wastewater Treatment Plant.

Commissioners/Committee Members that were present:

- Katherine Amidon (Environmental Planner, Bolton & Menk)
- Chip Bentley (Appalachian Council of Gov'ts.)
- Amanda Brock (Oconee County)
- Kevin Bronson (City of Westminster) – Committee Chair
- Chris Eleazer (Oconee Joint Regional Sewer Authority)
- Lawrence Flynn (Pope Flynn - OJRSA Attorney) – *via Microsoft Teams*
- Joel Jones (Consultant, JonesWater)
- Scott Moulder (City of Seneca)
- Celia Myers (City of Walhalla)

Committee Members that were not present:

- Angie Mettlen, (Vice President, Ardurra)

OJRSA appointments and staff present were:

- Lynn Stephens, Secretary/Treasurer to the Board and Office Manager

Others present were:

- Norm Cannada, The Journal
- Dick Mangrum, WGOG Radio

**A. Call to Order** – Mr. Bronson called the meeting to order at 2:05 p.m.

**B. Introduce the Members of the Committee** – Mr. Bronson asked each committee member to introduce themselves. Mr. Bronson stated he wants to keep each of these committee meetings down to one-hour intervals without stifling any conversation or concerns. He asked everyone if there were any objections to this; there were no objections.

**C. Discuss the Five (5) Recommendations of the Ad-Hoc Sewer Feasibility Implementation Committee (Exhibit A)** – Mr. Bronson stated that all but two (2) of the current committee members were on the Feasibility Implementation Committee, and he expressed his appreciation to them for their work in developing the recommendations. Mr. Bronson also noted that number four (#4) of the five (5) recommendations (dissolving the Ad-Hoc Feasibility Implementation Committee and creating an Ad-Hoc Reconstitution Committee) has already been completed by the OJRSA board. There were no other comments about these recommendations.

#### D. Committee Discussion and Action Items:

1. **Discussion and Approval of Support Resolution (Exhibit B)** – Mr. Bronson said Mr. Flynn drafted a simple resolution. He said there is a typo with the date on item G. It was discussed that the date should be July 15, 2025 and not June 16, 2025 as written.

Mr. Bronson said item B specifically states Seneca, Walhalla, and Westminster and asked if it should also include Oconee County and the Town of West Union. Mr. Flynn replied that West Union has the opportunity to join in the event they reach certain service thresholds (which haven't been met yet). He stated that for the Oconee County resolution, another finding would be added to state they are providing a recommendation based on a proposal to expand membership of the OJRSA, and he welcomes any comments from Oconee County personnel if they want something else to be added.

Mr. Bronson asked if Oconee County language is added, shouldn't that be on everyone's resolution in order that the same resolution is used across the entities? Mr. Flynn replied he could put in a general finding after item G since adding Oconee County is a recommendation. Mr. Bronson asked if Oconee County was good with that; Ms. Brock replied that Oconee County's attorney, Mr. David Root, will probably red line this. Ms. Brock said she already had a copy of this resolution and asked if this was the original or a new one; Mr. Flynn replied this is the original. Ms. Brock said she thinks Mr. Root will not red line it.

Mr. Bronson asked if there was any issue if each entity's resolution varied a little. Mr. Flynn replied this the resolution should be as standardized as possible, but it is not binding. The resolution is meant to establish common ground—that everyone is on board with the recommendations from the report and that no one is starting the process with serious misgivings. Mr. Flynn added that this is a difficult enough process, but the committee needs to ensure the foundation is strong to make it successful.

Mr. Bronson asked if Mr. Moulder had any issues. Mr. Moulder replied he didn't have any issues. He said there are a lot of questions, but this committee is charged with answering those questions on what implementation looks like. Mr. Bronson asked if the Appalachian Council of Governments (ACOG) is leaving it up to the entities; Mr. Bentley said yes. Mr. Moulder asked Mr. Bentley, as the 208 Water Quality Management, doesn't ACOG have some type of jurisdictional oversight; Mr. Bentley said they do but it is based on what the regional treatment facility is going to be and making sure everyone participates in it.

Mr. Eleazer asked if it was in the recommendation that the OJRSA should consider this within the 90-day timeline as well; Mr. Flynn replied that is correct. He added that it is probably a bit of overkill, but it shows the Rural Infrastructure Authority (RIA) and other governing bodies and the delegation that everyone is moving in the same direction with the goal being the long-term success of Oconee County and its municipalities. Mr. Moulder stated that it is beneficial as not all the representatives on the current OJRSA board are independent from the municipalities, so it gives them the opportunity to voice their opinions on the resolution.

Mr. Eleazer said he modified the resolution the OJRSA could use as best as he could and sent it to Mr. Flynn to finalize. He asked if it should go to the Finance and Administration Committee for consideration before going to the board. Mr. Bronson said it should go directly to the board since the Executive Committee is here and will approve it. Mr. Moulder and Ms. Myers agreed and said it could be sent back to the committee it needed.

Mr. Bronson said the timeline states the resolutions should be provided by October 13, 2025. He said that it is doable for Westminster and asked if it was doable with the other entities. Mr. Moulder, Ms. Myers, and Ms. Brock all stated that it was doable.

Mr. Flynn asked if he should create a template for each city or was everyone okay adapting it on their own with their councils. Mr. Bronson replied that he would like Mr. Flynn to add Oconee County. Mr. Moulder said he would like Mr. Flynn to draft one for everyone.

**2. Consider the Timeline as Stated in the Recommendations (Exhibit C)** – Mr. Bronson stated again that the first task is already completed and the resolution is to be done by October 13, 2025.

Ms. Brock said the recommendation by the Ad-Hoc Committee stated no more than two (2) representatives from the current board, and there are now three (3). She asked if this was changed by the board. Mr. Bronson said the recommendation was for the chair and vice-chair, but that would've left the City of Walhalla not being represented. The board wanted to be inclusive of the three (3) cities. Ms. Brock asked if the intent of the Ad-Hoc Committee was not to have that. Mr. Eleazer replied that the discussion was around having an odd number of members on this committee for voting purposes, but Mr. Flynn pointed out that if a tie-breaking vote was needed, there are bigger concerns to deal with. Ms. Brock said she agreed with that.

Mr. Moulder said the biggest obstacle and deliverable is in August 2026—determining who will be on the board and providing the list of recommendations to the delegation. Mr. Flynn said the amendments are important as it gives the delegation the recommendation authority, and the governor the gubernatorial appointment in lieu of the members. This will remove some of the politics.

Mr. Jones said there is a lot of leg work and asked Mr. Eleazer and Ms. Amidon if this is still practical. Ms. Amidon asked if it had been decided at what level that Ardurra and Bolton & Menk are to be involved. Mr. Bronson replied no and asked if Ms. Amidon had a recommendation. Ms. Amidon said she and Ms. Mettlen are here as third-party consultants supporting this committee by doing analysis and anything else consultants would do to get the committee to where it needs to be; however, the consultants cannot make the final decisions and choose the direction forward, because it won't be received well by the public. Mr. Bronson replied that Ms. Amidon, Ms. Mettlen, and Mr. Jones were invited onto this committee as non-voting members. Mr. Bronson asked if any of the other committee members had a recommendation about what the consultants will need to do in the process; there were no comments.

Mr. Bronson said he read in the minutes that the RIA would be open to helping finance the financial analysis. Ms. Amidon said that was a maybe; she said she knows by speaking with Ms. Bonnie Ammons of the RIA that they are looking for action at this end, and the resolution is only Step 1 of this action. RIA will also want to see some stakeholder commitment before they assist further as they feel they have already assisted with funding the feasibility study. Ms. Amidon added that she recommends this group going back to the recommendations that resulted from Weston & Sampson's Master Plan, because some of those things could get started during this reconstitution plan. She said she would be happy to take a pass with this. Mr. Bronson asked Ms. Amidon to do that first pass, and there could be a discussion about it at the next committee meeting.

Mr. Jones said a lot of money can be spent on the technical resources needed for the valuation and challenged the member agencies to determine what issues they have (technical or otherwise) to get through to allow the consolidation of their systems, and there may be a simpler solution to address this. Mr. Flynn said someone must do a deep dive on what the OJRSA board is taking on, and although everything won't be identified, it would be a good start with the system age, line degradation, and pump station utilization.

Mr. Bronson said this agenda doesn't state to adopt the timeline, but he asked if anyone was ready to adopt it. Mr. Bentley said it is fair to adopt but changes can be made.

***Mr. Bentley made a motion, seconded by Mr. Eleazer, to adopt the Timeline as presented.***

Ms. Brock stated that being Oconee County has so little technical valuations, it would be unfair for Oconee County to break a tie vote, so she may abstain. Mr. Eleazer said he put the timeline together based on the Ad-Hoc Feasibility Committee's recommendations, and they were target dates, so they can be adjusted. Ms. Brock said it is a motion to approve the timeline. Mr. Moulder asked Mr. Bentley if he wanted to change his motion.

***Mr. Bentley amended his motion, seconded by Mr. Eleazer, to adopt the Timeline as presented and to accept the dates in the timeline are target dates that the committee will try to maintain progress***

*towards, acknowledging that things may come up and require adjustments on the dates. The motion carried.*

**3. Submittal of Quarterly Reports to South Carolina Rural Infrastructure Authority (SC RIA) –** Mr. Bronson said he and Mr. Eleazer spoke about having Ms. Stephens submit the reports to the RIA, and he asked if Ms. Stephens was asked about doing this. Mr. Eleazer said he did not ask Ms. Stephens and said when he reported each milestone during the first Ad-Hoc Committee, he would just email Ms. Ammons and give a bullet point about what was done, and Ms. Ammons was appreciative of that. Mr. Eleazer also stated that Ms. Ammons could receive key points from the meeting minutes.

*Mr. Moulder made a motion, seconded by Mr. Bentley, to assign Sewer Authority staff with the responsibility of submitting the quarterly reports to the RIA. The motion carried.*

**4. Discuss Financial Evaluation of Wastewater Systems –** Mr. Bronson said he agreed with what Mr. Jones said earlier in the meeting that a lot of money can be spent on the valuations. Mr. Bronson asked, the way it is written in the report, if it is a deal breaker for any of the three (3) member cities and Oconee County, and he also asked if there were additional considerations this committee needs to have. Mr. Bronson added that this committee isn't tied to what they say, as they probably have not discussed it with their individual councils. Mr. Bronson said that although Westminster's council has received weekly reports, they haven't spoken about it in council yet either.

Mr. Moulder said that Seneca is in the same position and hasn't gotten feedback from its council on the recommendations. He said when they initially read the report, there were lots of questions about what the valuation, transfer, and debt would look like. This committee will have the job of answering these questions through the assessments. Mr. Moulder said Seneca is open to paying to bring in a team for a valuation of its system instead of having one (1) firm doing all the evaluations. He added that a lot of the financial analysis was performed during the report generation of the system with rates and customer base and asked if that could be reviewed and modified for condition analysis.

Mr. Bronson asked if it would be appropriate for each entity to go back and have these discussions with their individual councils and then bring the questions back to this committee to vet through. In addition, the councils should be asked if one (1) consultant should do all the valuations. Mr. Moulder was in favor of doing this.

Ms. Myers said she agreed with the feedback as well but added that the Ad-Hoc Committee was leaning towards one (1) consultant to do the valuations to keep the same parameters. Mr. Jones added that everyone should develop the scope through that one (1) consultant. Mr. Moulder was good with this.

Ms. Brock said the County Council is grateful to the Sewer Authority for having this amount of activity around change. She added she is good with getting the feedback but added that she may bring back many questions, and the answers presented may create even more questions. There was also some conversation about upcoming elections in the Member Cities and how more questions may be asked by new councilmembers.

Mr. Flynn suggested the question-and-answer part of the next committee meeting be held in Executive Session which would allow the committee members to speak freely. Mr. Moulder asked Mr. Flynn if that would follow the rules for holding an Executive Session, and Mr. Flynn felt it would.

Mr. Bronson asked if everyone felt they could have the discussions with their councils and have the questions to bring back in time for the next meeting. Everyone felt they could. There was some additional conversation about upcoming city elections that may bring up additional questions from new council members.

Ms. Amidon said that the valuation scope wouldn't be the same for everyone, as there are lots of unknowns. Mr. Eleazer stated that it should be the same scope sheet for each entity and that maybe the consultants could be utilized to put the analysis of the unknown items out for solicitation.

Ms. Amidon said the committee probably needs to determine what level of items need to be known for the valuation as it will cost more the more detail that is required.

Mr. Eleazer asked who was paying for this. Mr. Bronson said that is why he asked if the RIA was paying for it. This will need to be determined.

Ms. Amidon asked what the legal implications are for the OJRSA taking all these systems on if everyone is in support and is there anything the OJRSA needs to be aware of in terms of risk analysis. Mr. Flynn said the OJRSA is already accepting the waste from everyone's system, so the OJRSA is just taking on the cost of maintaining the collection systems, which is the cost of doing business. There is not a lot of heartburn on the legal side of the takeover.

- 5. Discuss Draft Language for State Law Modifications (Exhibit D)** – Mr. Bronson said the language states there will be a new board with a new way of it being created and the assets being owned collectively by one (1) entity. Mr. Bronson asked if there were any issues in the language Mr. Flynn drafted.

Mr. Flynn provided some background stating that he had preliminary conversations with the delegation, Senator Thomas Alexander, and his legislative liaisons. Being the legislature just finished year one of the two-year legislative cycle, the previous ad-hoc committee didn't want to waste a portion of the session. They wanted to get the language to a level where it's felt it allows the OJRSA to do all the things being proposed by the recommendations, giving the flexibility of the organization to be as successful as possible, and to use the political leverage of Senator Alexander to get it through. Mr. Flynn added that he feels the OJRSA is at the point if everyone is comfortable with it. Mr. Flynn stated it won't take anything away from what the OJRSA has but rather will add additional authorization on appointments, provide some clarifying language around issuance of bonds to make sure debt is properly approved, and provide the authority with more flexibility.

Mr. Bronson asked if everyone was comfortable making this a part of the presentation to their councils. Ms. Myers said it was already presented to the Walhalla council, and Mr. Bronson said it was to Westminster's council as well. Ms. Brock said, since Oconee County is not a part of the organization, they are good with it so far and want it to keep going. This isn't interesting to them just yet.

Mr. Bronson said he, Mr. Eleazer, and Mr. Flynn, (at a minimum) need to set up a meeting with the delegation, but he thinks this should be held off until this committee gets some feedback from the cities' and county's councils. Mr. Flynn said that makes good sense but recommended meeting with Senator Alexander in October to get some direction. The goal is to have the final introduction version in December, so it is ready to move come January 1, 2026.

Mr. Bronson asked Mr. Eleazer to contact Senator Thomas Alexander, Representative Bill Whitmore, and Representative Adam Duncan and share this information with them/lay the groundwork.

- 6. Establish Ad-Hoc Committee Meeting Schedule** – Mr. Bronson stated that the OJRSA board recommended having the meeting on the same day and time as the previous Ad-Hoc Feasibility Committee meeting: the second Thursday of each month at 9:00 a.m. All the committee members agreed.

Mr. Bronson summarized today's meeting:

- Ms. Amidon will do a preliminary review of the Master Plan and come back with anything the committee should review.
- The committee members will bring in a list of questions from their council members.
- The committee members will bring in an outline of specs and whether they are technical or financial.

**E. Upcoming Meetings**

1. **Operations & Planning Committee** – Wednesday, August 20, 2025 at 8:30 a.m.
2. **Finance & Administration Committee** – Tuesday, August 26, 2025 at 9:00 a.m.
3. **Board of Commissioners** – Monday, September 8, 2025 at 4:00 p.m.
4. **Ad-Hoc Reconstitution Committee** – Thursday, September 11, 2025 at 9:00 a.m. *(Meeting schedule established earlier in today's meeting.)*

**F. Adjourn** – The meeting was adjourned at 3:08 p.m.

Approved By: \_\_\_\_\_

Kevin Bronson  
Committee Chair

Date Approved: \_\_\_\_\_

Approved By: \_\_\_\_\_

Lynn M. Stephens  
OJRSA Secretary/Treasurer

Notification of the meeting was distributed on August 7, 2025 to *Upstate Today*, *Anderson Independent-Mail*, *Westminster News*, *Keowee Courier*, WGOG Radio, WSNW Radio, City of Seneca Council, City of Walhalla Council, City of Westminster Council, Oconee County Council, SC DHEC, [www.ojrsa.org](http://www.ojrsa.org), and posted at the OJRSA Administration Building.



## **Ad Hoc Reconstitution Committee and Executive Committee**

OJRSA Operations & Administration Building  
Lamar Bailes Board Room  
August 14, 2025 at 2:00 PM

*Amended – Meeting time corrected to 2:00 PM*

*This committee was established by the OJRSA Board of Commissioners on August 4, 2025 to consider the reorganization recommendations as identified in the [Ad Hoc Sewer Feasibility Implementation Committee Final Recommendations](#) report. This committee can neither create policy nor make decisions on behalf of the OJRSA or other wastewater service providers within the area. The report is available at [www.ojrsa.org/info](http://www.ojrsa.org/info).*

*OJRSA commission and committee meetings may be attended in person at the address listed above. The OJRSA will also broadcast meetings live on its YouTube channel at [www.youtube.com/@OconeeJRSA](http://www.youtube.com/@OconeeJRSA) (if there is a technical issue preventing the livestreaming of the meeting, then a recording will be published on the channel as soon as possible). For those not able to attend in person, then the OJRSA Board or Committee Chair will accept public comments by mail (623 Return Church Rd, Seneca, SC 29678) or at [info@ojrsa.org](mailto:info@ojrsa.org). Comments must comply with the public session instructions as stated on the meeting agenda and will be received up until one hour prior to the scheduled meeting. If there is not a public session scheduled for a meeting, then comments shall not be accepted.*

### **Agenda**

- A. Call to Order** – Kevin Bronson, Executive Committee Chair
- B. Introduce the Members of the Committee**
- C. Discuss the five recommendations of the Ad Hoc Sewer Feasibility Implementation Committee** (Exhibit A) – Led by Kevin Bronson, Executive Committee Chair
- D. Committee Discussion and Action Items** – Led by Kevin Bronson, Executive Committee Chair, unless otherwise noted
  1. Discussion and Approval of Support Resolution (Exhibit B)
  2. Consider the timeline as stated in the recommendations (Exhibit C)
  3. Submittal of quarterly reports to South Carolina Rural Infrastructure Authority (SC RIA)
  4. Discuss financial evaluation of wastewater systems
  5. Discuss draft language for state law modifications (Exhibit D)
  6. Establish ad hoc committee meeting schedule
- E. Upcoming Meetings** *All meetings to be held in the Lamar Bailes Board Room unless noted otherwise.*
  1. Operations & Planning Committee – August 20, 2025 at 8:30 AM
  2. Finance & Administration Committee – August 26, 2025 at 9:00 AM
  3. Board of Commissioners – September 8, 2025 at 4:00 PM
  4. Ad Hoc Reconstitution Committee – *Meeting schedule to be established as stated in agenda item D.6*
- F. Adjourn**





## REGIONAL SEWER FEASIBILITY STUDY

### OJRSA Ad Hoc Regional Feasibility Study Implementation Committee OJRSA Reorganization Recommendations

**June 16, 2025**

The OJRSA Regional Feasibility Planning Study (“Planning Study”), completed in August 2024 and adopted in September 2024, recommended establishing the Ad Hoc Regional Feasibility Study Implementation Committee (“Ad Hoc Committee”). The purpose of this committee was to review, discuss and evaluate the Planning Study’s primary recommendations for a new governance structure for Oconee Joint Regional Sewer Authority (“Authority”) and to provide independent recommendations for implementing this restructuring.

The Ad Hoc Committee was established by the Board of Commissioners, as the governing body of OJRSA (“Board”), in November 2024. The initial Ad Hoc Committee was staffed with 10 members, and one *ex officio* member as follows:

- Chip Bentley, *Ex Officio* Member
- Amanda Brock, Oconee County
- Chris Eleazer, OJRSA
- Joel Jones, Utility Expert (Environmental/Utility Compliance)
- Scott McLane, Seneca
- Celia Myers, Walhalla
- Scott Parris, Westminster
- Graham Rich, Utility Expert (Economic Development), *resigned*
- Sue Schneider, Utility Expert (Management)
- River Stillwell, Utility Legal Expert
- Scott Willett, Utility Expert (Finance)

The Planning Study suggested a six month timeline for the Ad Hoc Committee to review prior work and complete initial evaluations for recommendations that would be presented to the Board and Oconee County, as an entity recommended for addition to the Authority under the Planning Study.

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During the initial meeting, Graham Rich was elected Chair of the Ad Hoc Committee. Thereafter, Mr. Rich resigned due to personal reasons. The Ad Hoc Committee determined that they had an adequate number of utility experts with experience across all relevant areas, making a replacement unnecessary. Mr. Joel Jones, former CEO of Renewable Water Resources, was subsequently elected to serve as Chair moving forward, while the rest of the committee membership remained unchanged. Since December 2024, the Ad Hoc Committee has been convened monthly to advance this important process. All Ad Hoc Committee meetings were properly advertised and open to the public in accordance with the South Carolina Freedom of Information Act. The meetings of the Ad Hoc Committee were held on the dates noted below, and minutes from each such meeting are attached hereto for reference:

- December 2, 2024
- January 9, 2025
- February 13, 2025
- March 13, 2025
- April 10, 2025
- May 8, 2025
- June 16, 2025

**The following information outlines the Ad Hoc Committee's five major recommendations to reorganize/reconstitute the Authority under the Joint Authority Water and Sewer Systems Act.**

**1. The collection systems of current Authority members and Oconee County should be consolidated into one combined system – owned, operated, and maintained by the reconstituted Authority.**

- Timely evaluations (technical) and valuations (financial) of the collection systems, including debt, asset viability, and immediate capital, are essential to finalize the terms of the system transfers to the Authority. This step is crucial in the process and should be completed as soon as possible. *(NOTE: For the consolidation of the current collection systems into the reconstituted Authority, the Town of West Union should be included in this effort.)*
- It is recommended that all affected entities, to include the Board, the governing bodies of each member of the Authority (Walhalla, Westminster and Seneca), Oconee County Council, and the West Union Town Council, adopt a

resolution expressing initial support for this consolidation effort. The resolutions can be non-binding and contingent upon the final terms and conditions of the transfers. However, it would demonstrate a unified approach and support for the overall process, potentially aiding in the acquisition of any future grant funding or other forms of financial support.

- A unified and equitable rate structure will be developed and deployed as a part of the governance documents of the reconstituted Authority. A timeline for developing and implementing this rate structure will be completed as soon as possible.
- If the consolidation of any or all collection systems does not progress in a timely manner, or at all, the Authority, in its current form, must issue individual permits to each entity that retains ownership of those systems. These permits will necessitate ongoing compliance with the Authority’s Sewer Use Regulation (“SUR”), which is further mandated by the Authority’s National Pollutant Discharge Elimination System (“NPDES”) permit issued by the South Carolina Department of Environmental Services (“SCDES”). This action will empower the Authority to enforce the conditions of these permits as outlined in the SUR. Further, SCDES recently confirmed that the agency’s expectation is that the Authority enforce its SUR for all upstream users as necessary to comply with the Authority’s own NPDES permit. Any permits issued to the current member entities, Oconee County, and/or Town of West Union<sup>1</sup> would reflect this regulatory expectation, though the precise terms would be left to the Authority’s discretion.

## **2. The Authority should be reconstituted with a five-member Board of Commissioners (the “New Board”).**

Based on the Joint Authority Water and Sewer Systems Act (SC Code Ann §§6-25-5, et. seq.) (“Act”), a “member of a joint system” is defined as “an authority that has

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<sup>1</sup> Anecdotally, SCDES shared that it is presently dealing with a situation elsewhere in the state involving a wastewater utility with compliance difficulties linked to a single large upstream user. In that situation, EPA has recommended that SCDES make the utility and each satellite user a co-permittees on the upcoming renewal of the utilities’ NPDES permit. Such action creates jointly and severally responsibility to the state and federal government for all noncompliance going forward. In the absence of the recommended consolidation or issuance of individual permits, it is possible regulators could impose such a co-permittee scenario on the Authority and all member entities in the future.

taken the actions necessary to form or join the joint system.” Based on this definition, the members with representative interests on the New Board will be the City of Seneca, the City of Walhalla, the City of Westminster and Oconee County. Draft legislation has been proposed to amend the Act to permit new methods for appointing commissioners to a joint authority. Conversations with legislative leadership have been ongoing, and proposed changes to the Act are expected to be considered during the 2026 legislative session at the earliest.<sup>2</sup> A copy of the proposed legislative changes to the Act are attached to this recommendation report.

Assuming these changes are approved, the full appointment of the commissioners to the New Board will be made by the Governor of South Carolina, based upon the recommendations of the Oconee County Legislative Delegation (the “Delegation”).

**The following bullets provide the basic guidelines for commissioner recommendations. These will be outlined in the governance documents for the reconstituted Authority:**

- All commissioners must reside within the service territory of the member to whom they are appointed to represent and have a service contract for public sewer at the time of appointment and for the duration of their term. At least one commissioner of the New Board shall be appointed from the service area of each member of the joint authority (i.e. one from Westminster, Walhalla, Seneca, and Oconee County, respectively).
- Gubernatorial appointed commissioners cannot be current elected officials or current staff of any Authority member.
- Clarifying language will be included in the governance documents for the reconstituted Authority to address changes to the Authority’s service territory and the potential impact on the appointment of future Commissioners. In general, if areas outside Oconee County are served, such customers would be

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<sup>2</sup> If the legislative changes fail or take longer to be approved, the current Authority governance documents could be dissolved by the current Board and member entities and new governance documents drafted. In such event, it is recommended that the reconstituted Authority be served by a five-member New Board and subject to the parameters outlined in the Committee’s Recommendation 2. This act is further predicated on unequivocal endorsement that all of the existing collection systems be consolidated into a single system.

by contract and the New Board would not be expanded (*i.e.*, *Anderson County*).

- Terms of commissioners will be dictated by the revised Act and will generally be for 4 years.
- Under this New Board structure and with collection system consolidation, all votes will be based on one vote per commissioner. All other voting protocols will be defined in the new governance documents.

**If the proposed legislative amendments to the Act are not enacted, the New Board will not be recommended by the Delegation and appointed by the Governor but rather will continue under the current method of appointment whereby the members of the Authority appoint their respective representatives to the New Board. The following bullets provide the basic guidelines for Commissioner recommendations in the event the proposed legislative amendments are not adopted:**

- For the New Board representation should be as follows:
  - City of Seneca – Recommendation for 1 commissioner;
  - City of Walhalla – Recommendation for 1 commissioner;
  - City of Westminster – Recommendation for 1 commissioner;
  - Oconee County – Recommendation for 1 commissioner; and
  - Recommendation for 1 at-Large commissioner to be agreed upon by Seneca, Walhalla, Westminster and Oconee County
- Best efforts should be undertaken to avoid the appointment of any commissioner that involves current staff of any member or any elected official. It is strongly encouraged that the bylaws of the New Board expressly prohibit any such *ex officio* or principal/agent service on the New Board.
- Clarifying language will be included in the governance documents for the reconstituted Authority to address changes to the Authority’s service area and the potential impact on the appointment of future Commissioners. In general, if areas outside Oconee County are served, these would be by contract and the Board would not be expanded.

- Consistent with the Act, commissioner to serve at discretion of the members.
  - Under this New Board structure and with collection system consolidation, all votes will be based on one vote per Commissioner. All other voting protocols will be defined in the new governance documents.
3. **The governance documents of the reconstituted Authority will be drafted and supersede all existing Authority governance documents and contracts, which must be dissolved as a part of this process. These documents will also provide that the reconstituted Authority will have the power to provide retail sewer services within its service area as necessary to support the operation of the consolidated collection systems. This should be finalized upon completion of the consolidation but can be drafted during the consolidation process.**
  4. **The current Board will dissolve the current Ad Hoc Committee and then establish a working group or smaller ad hoc committee to oversee and guide the initial implementation steps outlined above (the “Implementation Committee”). The Implementation Committee is recommended to include:**
    - No more than 2 representatives of the current Board. Suggestion that these committee seats be held by the Board Chair and Vice Chair, since these positions are voted on by the current Board.
    - 1 representative of OJRSA staff.
    - 1 representative of Oconee County.
    - 1 representative of the Appalachian Council of Governments (ACOG).
    - No more than 2 additional facilitators (non-voting) may also be recommended.
    - Independent legal counsel should also remain actively involved in all consolidation efforts to ensure compliance with all legal requirements.
  5. **It is recommended that a Communications Plan for the reorganization be developed, which should be used by all entities involved. This plan will ensure clear and consistent messaging while also allowing for input from residents and customers of the Authority. Maintaining an open process is crucial to maximize**

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**the chances of success in consolidating the collection systems and establishing the reconstituted Authority with the New Board.**

**Summary Statement:**

**The Ad Hoc Committee believes the foregoing recommendations to be vital to the long-term success of the Authority. In the absence of the implementation of these recommendations, the Authority runs the risk of significant regulatory compliance matters, lack of funding, and restrictions on growth and development of the County as a whole. As a plan to implement these recommendations, an implementation timeline is attached hereto as Exhibit A and incorporated herein by reference.**

ACCEPTED BY THE OJRSA BOARD OF COMMISSIONERS JULY 15, 2025

## EXHIBIT A IMPLEMENTATION TIMELINE

The following bullets provide a target schedule associated with completion of these initial recommendations. The schedule begins when the current Board approves these Reorganization Recommendations:

- **Within 45 days**, the current Board will dissolve the current Ad Hoc Committee and establish the Implementation Committee for further implementation oversight.
- **On a quarterly basis**, the Implementation Committee will provide an update to the SC Rural Infrastructure Authority, the current Board and Oconee County on the progress of the implementation of these initial recommendations.
- **Within 45 days**, the legislative revisions to the Act will be finalized and provided to the Delegation. Consultation shall be made with the Delegation on whether lobbyist support will be needed.
- **Within 90 days**, resolutions of support for system consolidation/Authority reorganization will be provided to and adopted by each governing body affected by the recommendations, including the Board, Seneca City Council, Walhalla City Council, Westminster City Council, West Union Town Council, Oconee County Council).
- **Within 120 days**, consultants shall be engaged, and the process of collection system evaluation (technical) and valuation (financial) will be initiated, including identification of potential funding for this effort and immediate rehabilitation projects that may be identified or on current Capital Improvement Plans. Additionally, a rate consultant will be engaged.
- **Within 120 days**, a Communications Plan will be developed under the guidance of the Implementation Committee and provided to all entities involved.
- **Within 60 days of the approved changes to Act being approved (likely July/August 2026)**, the list of recommendations for the initial commissioners for the New Commission will be provided to the Delegation.
- **Within 15 months**, after consultant engagement the evaluation and valuation of collection systems will be completed.
- **Within 18 months**, after consultant engagement the determination of a timeline for developing a unified, equitable rate structure will be provided as a part of the initial terms for collection system consolidation.
- **Within 24 months**, legal documents to transfer collection system assets to the Authority will be executed, as well as all necessary reconstitution documents.

## EXHIBIT 1

- **Within 25 months**, if the legislative amendments have not be approved, plans for consolidation under the amended Act will be abandoned. Thereupon, the Authority will proceed to consolidate the member system and implement the reconstitution under the existing Act, with such process to be finalized by no later than **36 months**. Additionally, all members shall be issued permits in compliance with the SUR and added as co-permittees under the NPDES permit, if consolidation for any member does not occur.

ACCEPTED BY THE OJRSA BOARD OF COMMISSIONERS JULY 15, 2025

## **ATTACHMENTS**

- **Copies of Minutes of Ad Hoc Committee Meetings**
- **Draft of Proposed Amendments to the Act**

TO AMEND CERTAIN PROVISIONS OF TITLE 6, CHAPTER 25 OF THE CODE OF LAWS OF SOUTH CAROLINA 1976, TO AUTHORIZE CERTAIN CLARYIFYING AMENDMENTS REGARDING COMMISSIONERS, RECONSTITUTION, BOND APPROVAL AND DURATION.

Be it enacted by the General Assembly of the State of South Carolina:

**SECTION 1. Section 6-25-20 shall be amended to add the following defined terms:**

**§ 6-25-20. Definitions.**

(14) "Legislative Delegation" means all members of the South Carolina Senate and South Carolina House representing any county where a joint system is located.

(15) "Governor" means the Governor of the State of South Carolina.

**SECTION 2. Section 6-25-50 shall be amended and restated as follows:**

**§ 6-25-50.** ~~Agreement as to number of commissioners each member may appoint;~~ Application filed with Secretary of State; corporate certificate.

(A) The governing bodies of the members of a joint system shall form an agreement specifying the number of commissioners ~~each member may appoint to a commission created to govern the joint system pursuant to Section 6-25-60.~~

(B) ~~Two or more commissioners~~ The proposed members of a joint system shall jointly file an application with the Secretary of State ~~an application signed by the commissioner or each proposed member setting forth:~~

(1) ~~the names of~~ number of proposed members of the joint system, the number of proposed commissioners, and their respective appointed commissioners the method of appointment pursuant to Section 6-25-60(B);

(2) ~~(a) the a~~ certified copy of a resolution of each member determining it is in its best interest to participate in the proposed joint system; and

~~(b) the resolution appointing the member's commissioner;~~

(3) the desire that the joint system be organized as a public body corporate and politic under this chapter;

(4) the name which is proposed for the joint system; and

(5) the purpose for creation of the joint system.

The Secretary of State shall file the application if after examining it and determining that it complies with the requirements in this section and that the proposed name of the joint system is not identical with that of any other corporation of the State or any agency or instrumentality or so nearly similar as to lead to confusion and uncertainty.

After the application has been filed, the Secretary of State shall issue a corporate certificate that must be filed with the application, and the joint system then must be constituted a public body corporate and politic under the name proposed in the application. The corporate certificate shall set forth ~~the names of all voting member and~~ the name of the joint system. There also must be stated upon the corporate certificate the purpose for which it has been created, as set forth in the application. Notice of the issuance of such corporate certificate must be given to all members of the joint system by the Secretary of State.

In any suit, action, or proceeding involving the validity or enforcement of, or relating to, contract of a joint system, the joint system in the absence of establishing fraud shall be conclusively

considered to have been established in accordance with the provisions of this chapter upon proof of the issuance of the certificate by the Secretary of State. A copy of the certificate, duly certified by the Secretary of State, is admissible in evidence in any suit, action, or proceeding and is conclusive proof of the filing and contents.

**SECTION 3. Section 6-25-60 shall be amended and restated as follows:**

§ 6-25-60. Joint system to be managed and controlled by commission; appointment of commissioners; oath; records; seal; quorum; vacancies; expenses.

(A) The management and control of a joint system is vested in a commission that may consist of no fewer than five members and no more than eleven members. A commissioner has one vote and may have additional votes as a majority of the members of the joint system determines. Notwithstanding the provisions of this subsection requiring the commission managing a joint system to have no fewer than five members and no more than eleven members, a joint system in existence on this section's effective date and having fewer than five members or more than eleven members on this section's effective date may continue to maintain the number of members serving on the section's effective date and may add additional members as its commissioners determine.

(B) As contemplated by the initial application to the Secretary of State, commissioners serving on the commission may be appointed under one of the following procedures:

(1) Appointment by member. The governing body of each voting member of a joint system shall appoint one or more a commissioner, pursuant to ~~Section 6-25-50(A)~~, to serve as a commissioner of the joint system. ~~A commissioner has one vote and may have additional votes as a majority of the members of the joint system determines.~~ A commissioner serves at the pleasure of the governing body by which he was appointed. A commissioner, before entering upon his duties, shall take and subscribe to an oath before a person authorized by law to administer oaths to execute the duties of his office faithfully and impartially, and a record of each oath must be filed with the governing body of the appointing authority.

~~Notwithstanding the provisions of this subsection requiring the commission managing a joint system to have no fewer than five members and no more than eleven members, a joint system in existence on this section's effective date and having fewer than five members or more than eleven members on this section's effective date may continue to maintain the number of members serving on the section's effective date and may add additional members as its commissioners determine.~~ Further, and notwithstanding the appointment requirements above, in the event there are an even number of members of a joint system (i.e. 4, 6, 8, 10), the project contract, bylaws or other similar agreement for the joint system may authorize one additional member of the commission; such additional commissioner shall be recommended by the legislative delegation from each county where the joint system is located, and upon receipt of such recommendation, such additional commissioner shall appointed by the Governor. Any gubernatorial appointment shall be for a term of four years and shall serve until a duly appointed successor is appointed and qualified. Any commissioner appointed by the Governor hereunder must reside within a household receiving utility services from the joint system or a member of the joint system. Any vacancy of such member must be filled for the remainder of the unexpired term in the same manner as the original appointment. If a new member of a joint system is added under the provisions hereof such that there becomes an odd number of members of a joint system, any gubernatorial appointed commissioner shall be deemed to automatically vacate his position as a commissioner as of the date of the admission of such new member of a joint system and their respective appointment of a new commissioner.

(2) Appointment by Governor. The commissioners may be appointed by the Governor in accordance with the following procedures:

(a) The Governor, based upon the recommendation of the legislative delegation from each county that the joint system operates, shall appoint each commissioner. Each appointed commissioner must reside within a household receiving utility services from the joint system or a member of the joint system. In making such appointments, there shall be at least one commissioner appointed by the Governor from the service area of each member of the joint system.

(b) Excepting the initial appointments as necessary to create a staggered commission which may be two or four years, respectively, each commissioner must be appointed and serve for a term of four years and until his successor is appointed and qualified, provided that the terms of the commissioners must be staggered such that approximately one-half of the total members appointed by the Governor must be appointed or reappointed every two years. A vacancy must be filled for the remainder of the unexpired term in the manner of the original appointment. Respecting the initial commission appointed herein, the minority portion of the staggered membership, representing those authorities with the lowest number of customers of the joint system, shall serve for an initial two-year term.

~~(B)~~ (C) The commissioners of the joint system shall annually, or biennially, if provided in the bylaws of the joint system, elect, with each commissioner having one vote, one of the commissioners as chairman, another as vice chairman, and other persons who may, but need not be commissioners, as treasurer, secretary and, if desired, assistant secretary. The office of treasurer may be held by the secretary or assistant secretary. The commission may also appoint such additional officers as it deems necessary. The secretary or assistant secretary of the joint system shall keep a record of the proceedings of the joint system, and the secretary must be the custodian of all books, records, documents, and papers filed with the joint system, the minute book or journal of the joint system, and its official seal.

~~(C)~~ (D) A majority of the commissioners of the joint system shall constitute a quorum. A vacancy on the commission of the joint system shall not impair the right of a quorum to exercise all rights and perform all the duties of a joint system. Any action taken by the joint system under the provisions of this chapter may be authorized by resolution at any regular or special meeting held pursuant to notice in accordance with bylaws of the joint system, and each resolution shall take effect immediately and need not be published or posted. Except as is otherwise provided in this chapter or in the bylaws of the joint system, a majority of the votes which the commissioners present are entitled to cast, with a quorum present, shall be necessary and sufficient to take any action or to pass any resolution. No commissioner of a joint system shall receive any compensation solely for the performance of duties as a commissioner, but each commissioner may be paid per diem, mileage, and subsistence expenses, as provided by law for state boards, committees, and commissions, incurred while engaged in the performance of such duties.

(E) All commissioners shall hold the qualifications of an elector.

(F) Commissioners appointed under subsection (B)(2) above may not be an officer or employee of a member of a joint system, and no commissioner shall be permitted to serve on an ex officio basis. Separately, for commissioners appointed under subsection (B)(1) above, the members of the joint system may include a restriction in the project contract, bylaws or other agreement for the joint system that no commissioner may be an officer or employee of a member of a joint system, and no commissioner shall be permitted to serve on an ex officio basis.

(G) Any commissioner appointed hereunder shall be deemed to forfeit his respective position if such person (1) lacks, at any time during his term of office, any qualifications for the office prescribed by general law and the Constitution, or (2) is convicted of any crime, other than civil infractions or misdemeanors for which no imprisonment is imposed.

**SECTION 4. Section 6-25-70 shall be amended and restated as follows:****SECTION 6-25-70.** Change in membership of joint system.

(A) After the creation of a joint system, any other authority may become a member *of the joint system* upon:

(1) adoption of a resolution or ordinance by the governing body complying with the requirements of Section 6-25-40 including publication of notice;

(2) submission of an application to the joint system; and

(3) approval of the application by resolution of the governing body of each member of the joint system except in the case of a joint system organized for the purpose of creating a financing pool, in which case the application must be approved by resolution of the commission.

(B) A member may withdraw from a joint system by resolution or ordinance of its governing body. A contractual right acquired or contractual obligation incurred by a member while it was a member remains in full force and effect after the member's withdrawal.

(C) Notice of a change in membership must be filed in the Office of the Secretary of State. No change is final until this filing occurs. The filing is not required if a joint system is organized only for the purpose of creating a financing pool.

(D) If a new member of the joint system is added hereunder, the approval documentation required under subsection (A)(3) above shall determine whether any new commissioners shall be added to the commission as necessary to support such new member of the joint system. If a new commissioner is added, either by the member of the joint system or the Governor, as applicable, each such commissioner shall be appointed immediately.

**SECTION 5. Section 6-25-80 shall be amended and restated as follows:****§ 6-25-80.** Dissolution of system.

Whenever the commission of a joint system and the governing body of each of its members shall by resolution or ordinance determine that the purposes for which the joint system was formed have been substantially fulfilled and that all bonds issued and all other obligations incurred by the joint system have been fully paid or satisfied, the commission and members may declare the joint system to be dissolved. On the effective date of the resolution or ordinance, the title to all funds and other income and property owned by the joint system at the time of dissolution must be disbursed to the voting members of the joint system according to its bylaws.

In the discretion of the members of a joint system for the proper and efficient operation of any joint system, an existing joint system may be reconstituted by following the procedures for the creation of a new joint system, mutatis mutandis.

**SECTION 6. Section 6-25-110 shall be amended and restated as follows:****§ 6-25-110.** Authorization to incur debt and issue bonds.

A joint system may incur debt for any of its purposes and may issue bonds pledging to the payment as to both principal and interest the revenues, or any portion, derived or to be derived from all or any of its projects and any additions and betterments or extensions or contributions or advances from its members or other sources of funds available to it. A joint system may not undertake a project required to be financed, in whole or in part, with the proceeds of bonds without the approval of the governing bodies of each member which is obligated or to be obligated under any contract for the payment of amounts to be pledged as security therefore and a favorable vote of two-thirds of all commissioners. Notwithstanding the foregoing, when a commission is

appointed under Section 6-25-60(B)(2), no separate approval of the governing bodies of each member shall be required for the issuance of any bonds, and such bonds shall be authorized and approved by a simple majority of the commissioners. Any project may be preauthorized, preapproved or otherwise permitted under the terms of the project contract for the joint system, and such authority, approval or permission shall constitute all necessary approval of the respective governing bodies of each member herein. A joint system formed only for the purpose of creating a financing pool may issue notes in anticipation of the issuance of bonds by its members to the government.

**SECTION 7. Section 6-25-128 shall be amended and restated as follows:**

**§ 6-25-128.** Contracts between authority and joint system; duration.

An authority may contract to buy from the joint system water required for its present or future requirements, including the capacity and output, or a portion or share of one or more specified projects. An authority also may contract for the collection or treatment of wastewater, including present or future capacity, or a portion or share of another project. The creation of a joint system is an alternative method whereby an authority may obtain the benefits and assume the responsibilities of ownership in a project, so a contract may provide that the authority forming the contract is obligated to make a payment required by the contract whether or not a project is completed, operable, or operating notwithstanding the suspension, interruption, interference, reduction, or curtailment of the output of a project or the water contracted for, and that the payments under the contract are not subject to reduction, whether by offset or otherwise, and are not conditioned upon the performance or nonperformance of the joint system or any other member of the joint system under the contract or any other instrument. A contract with respect to the sale or purchase of capacity or output, or a portion or share of them, of a project entered into between a joint system and its member authorities also may provide that if an authority or authorities default in the payment of its or their obligations with respect to the purchase of the capacity or output, or a portion or share of them, in that event the remaining member authorities which are purchasing capacity and output under the contract are required to accept and pay for and are entitled proportionately to and may use or otherwise dispose of the capacity or output which was to be purchased by the defaulting authority.

A contract concerning the sale or purchase of capacity and output from a project may extend for a period not exceeding fifty years from the date of the contract and may be renewable and extended upon terms as the parties may agree for not exceeding an additional fifty years; and the execution and effectiveness is not subject to any authorizations or approvals by the State or any agency, commission, or instrumentality or political subdivision of them. Additionally, the contract may further provide that bonds or other indebtedness of the joint system may exceed the term of an initial or existing contract between or among the joint system and the respective members of the joint system, and in such event the contract, or at least the payment obligations of each member, shall be automatically extended to a period commensurate with the term of the bonds or other indebtedness.

Payments by an authority under a contract for the purchase of capacity and output from a joint system may be made from the revenues derived from the ownership and operation of the water system of the authority or from such other sources of funds as may be available, including any amounts received as payments in lieu of taxes. An authority may not pledge its full faith, credit, and taxing power to secure its obligations to the joint system or the bonds of the joint system. An authority is obligated to fix, charge, and collect rents, rates, fees, and charges for water or sewer services, facilities, and commodities sold, furnished, or supplied through its water or sewer system sufficient to provide revenues adequate to meet its obligations under any contract and to pay any

ACCEPTED BY THE OJRSA BOARD OF COMMISSIONERS JULY 15, 2025

and all other amounts payable from or constituting a charge and lien upon the revenues, including amounts sufficient to pay the principal of and interest on general obligation bonds, if any, heretofore or hereafter issued by the authority for purposes related to its water or sewer system.

An authority that is a member of a joint system may furnish the joint system with money derived from the ownership and operation of its water or sewer system or facilities and provide the joint system with personnel, equipment, and property, both real and personal, and from any other sources legally available to it for such purposes. An authority also may provide services to a joint system.

A member of a joint system may contract for, advance, or contribute funds derived from the ownership and operation of its water or sewer system or facilities or from another legal source to a joint system as agreed upon by the joint system and the member, and the joint system shall repay the advances or contributions from the proceeds of bonds, operating revenue, or other funds of the joint system, together with interest as agreed upon by the member and the joint system.

**SECTION 8. This act takes effect upon approval by the Governor.**

TO AMEND CERTAIN PROVISIONS OF TITLE 6, CHAPTER 25 OF THE CODE OF LAWS OF SOUTH CAROLINA 1976, TO AUTHORIZE CERTAIN CLARYIFYING AMENDMENTS REGARDING COMMISSIONERS, RECONSTITUTION, BOND APPROVAL AND DURATION.

Be it enacted by the General Assembly of the State of South Carolina:

**SECTION 1. Section 6-25-20 shall be amended to add the following defined terms:**

**§ 6-25-20. Definitions.**

(14) "Legislative Delegation" means all members of the South Carolina Senate and South Carolina House representing any county where a joint system is located.

(15) "Governor" means the Governor of the State of South Carolina.

**SECTION 2. Section 6-25-50 shall be amended and restated as follows:**

**§ 6-25-50.** ~~Agreement as to number of commissioners each member may appoint;~~ Application filed with Secretary of State; corporate certificate.

(A) The governing bodies of the members of a joint system shall form an agreement specifying the number of commissioners ~~each member may appoint to a commission created to govern the joint system pursuant to Section 6-25-60.~~

(B) ~~Two or more commissioners~~ The proposed members of a joint system shall jointly file an application with the Secretary of State ~~an application signed by the commissioner or each proposed member~~ setting forth:

(1) ~~the names of~~ number of proposed members of the joint system, the number of proposed commissioners, and their respective appointed commissioners the method of appointment pursuant to Section 6-25-60(B);

(2) ~~(a) the a~~ certified copy of a resolution of each member determining it is in its best interest to participate in the proposed joint system; ~~and~~

~~(b) the resolution appointing the member's commissioner;~~

(3) the desire that the joint system be organized as a public body corporate and politic under this chapter;

(4) the name which is proposed for the joint system; and

(5) the purpose for creation of the joint system.

The Secretary of State shall file the application if after examining it and determining that it complies with the requirements in this section and that the proposed name of the joint system is not identical with that of any other corporation of the State or any agency or instrumentality or so nearly similar as to lead to confusion and uncertainty.

After the application has been filed, the Secretary of State shall issue a corporate certificate that must be filed with the application, and the joint system then must be constituted a public body corporate and politic under the name proposed in the application. The corporate certificate shall set forth ~~the names of all voting member and~~ the name of the joint system. There also must be stated upon the corporate certificate the purpose for which it has been created, as set forth in the application. Notice of the issuance of such corporate certificate must be given to all members of the joint system by the Secretary of State.

In any suit, action, or proceeding involving the validity or enforcement of, or relating to, contract of a joint system, the joint system in the absence of establishing fraud shall be

conclusively considered to have been established in accordance with the provisions of this chapter upon proof of the issuance of the certificate by the Secretary of State. A copy of the certificate, duly certified by the Secretary of State, is admissible in evidence in any suit, action, or proceeding and is conclusive proof of the filing and contents.

**SECTION 3. Section 6-25-60 shall be amended and restated as follows:**

§ 6-25-60. Joint system to be managed and controlled by commission; appointment of commissioners; oath; records; seal; quorum; vacancies; expenses.

(A) The management and control of a joint system is vested in a commission that may consist of no fewer than five members and no more than eleven members. *A commissioner has one vote and may have additional votes as a majority of the members of the joint system determines. Notwithstanding the provisions of this subsection requiring the commission managing a joint system to have no fewer than five members and no more than eleven members, a joint system in existence on this section's effective date and having fewer than five members or more than eleven members on this section's effective date may continue to maintain the number of members serving on the section's effective date and may add additional members as its commissioners determine.*

*(B) As contemplated by the initial application to the Secretary of State, commissioners serving on the commission may be appointed under one of the following procedures:*

*(1) Appointment by member.* The governing body of each voting member of a joint system shall appoint *one or more* a commissioner, ~~pursuant to Section 6-25-50(A),~~ to serve as a commissioner of the joint system. ~~A commissioner has one vote and may have additional votes as a majority of the members of the joint system determines.~~ A commissioner serves at the pleasure of the governing body by which he was appointed. A commissioner, before entering upon his duties, shall take and subscribe to an oath before a person authorized by law to administer oaths to execute the duties of his office faithfully and impartially, and a record of each oath must be filed with the governing body of the appointing authority.

~~Notwithstanding the provisions of this subsection requiring the commission managing a joint system to have no fewer than five members and no more than eleven members, a joint system in existence on this section's effective date and having fewer than five members or more than eleven members on this section's effective date may continue to maintain the number of members serving on the section's effective date and may add additional members as its commissioners determine.~~ *Further, and notwithstanding the appointment requirements above, in the event there are an even number of members of a joint system (i.e. 4, 6, 8, 10), the project contract, bylaws or other similar agreement for the joint system may authorize one additional member of the commission; such additional member of the commission commissioner shall be recommended by the legislative delegation from each county where the joint system is located, and upon receipt of such recommendation, such additional member commissioner shall appointed by the Governor. Any gubernatorial appointment shall be for a term of four years and shall serve until a duly appointed successor is appointed and qualified. Any commissioner appointed by the Governor hereunder must reside within a household receiving utility services from the joint system or a member of the joint system. Any vacancy of such member must be filled for the remainder of the unexpired term in the same manner as the original appointment. If a new member of a joint system is added under the provisions hereof such that there becomes an odd number of members of a joint system, any gubernatorial appointed commissioner shall be deemed to automatically vacate his position as a commissioner as of the date of the admission of such new member of a joint system and their respective appointment of a new commissioner.*

(2) Appointment by Governor. The commissioners may be appointed by the Governor in accordance with the following procedures:

~~(a) The total number of customers served by the joint system (including customers served by members of the joint system) must be divided by the total number of commission seats, the result being an apportionate average.~~

~~(b) The respective number of customers of each member of the joint system must be divided by the apportionate average to determine an appointive index.~~

(ea) The Governor, based upon the recommendation of the legislative delegation from each county that the joint system operates, shall appoint ~~a number of commissioners to the commission from each~~each commissioner. Each appointed commissioner must reside within a household receiving utility services from the joint system or a member of the joint system ~~equal to the whole number indicated by its appointive index. If by this method there are insufficient members appointed to complete the commission, an appointive index closest to the next highest whole number shall be authorized to have an additional commissioner. Further, and notwithstanding the appointive index.~~ In making such appointments, there shall be at least one commissioner appointed by the Governor from the service area of each member of the joint system.

(db) Excepting the initial appointments as necessary to create a staggered commission which may be two or four years, respectively, each commissioner must be appointed and serve for a term of four years and until his successor is appointed and qualified, provided that the terms of the commissioners must be staggered such that approximately one-half of the total members appointed by the Governor must be appointed or reappointed every two years. A vacancy must be filled for the remainder of the unexpired term in the manner of the original appointment. Respecting the initial commission appointed herein, the minority portion of the staggered membership, representing those ~~members~~authorities with the lowest ~~appointive index~~number of customers of the joint system, shall serve for an initial two-year term.

~~(B)~~ (C) The commissioners of the joint system shall annually, or biennially, if provided in the bylaws of the joint system, elect, with each commissioner having one vote, one of the commissioners as chairman, another as vice chairman, and other persons who may, but need not be commissioners, as treasurer, secretary and, if desired, assistant secretary. The office of treasurer may be held by the secretary or assistant secretary. The commission may also appoint such additional officers as it deems necessary. The secretary or assistant secretary of the joint system shall keep a record of the proceedings of the joint system, and the secretary must be the custodian of all books, records, documents, and papers filed with the joint system, the minute book or journal of the joint system, and its official seal.

~~(C)~~ (D) A majority of the commissioners of the joint system shall constitute a quorum. A vacancy on the commission of the joint system shall not impair the right of a quorum to exercise all rights and perform all the duties of a joint system. Any action taken by the joint system under the provisions of this chapter may be authorized by resolution at any regular or special meeting held pursuant to notice in accordance with bylaws of the joint system, and each resolution shall take effect immediately and need not be published or posted. Except as is otherwise provided in this chapter or in the bylaws of the joint system, a majority of the votes which the commissioners present are entitled to cast, with a quorum present, shall be necessary and sufficient to take any action or to pass any resolution. No commissioner of a joint system shall receive any compensation solely for the performance of duties as a commissioner, but each commissioner may be paid per diem, mileage, and subsistence expenses, as provided by law for state boards, committees, and commissions, incurred while engaged in the performance of such duties.

(E) All commissioners shall hold the qualifications of an elector. ~~In the case of a gubernatorial appointment, such appointee must be a qualified elector residing within the area served by the joint system.~~

(F) Commissioners appointed under subsection (B)(2) above may not be an officer or employee of a member of a joint system, and no commissioner shall be permitted to serve on an ex officio basis. Separately, for commissioners appointed under subsection (B)(1) above, the members of the joint system may include a restriction in the project contract, bylaws or other agreement for the joint system that no commissioner may be an officer or employee of a member of a joint system, and no commissioner shall be permitted to serve on an ex officio basis.

(G) Any commissioner appointed hereunder shall be deemed to forfeit his respective position if such person (1) lacks, at any time during his term of office, any qualifications for the office prescribed by general law and the Constitution, or (2) is convicted of any crime, other than civil infractions or misdemeanors for which no imprisonment is imposed.

**SECTION 4. Section 6-25-70 shall be amended and restated as follows:**

**SECTION 6-25-70.** Change in membership of joint system.

(A) After the creation of a joint system, any other authority may become a member of the joint system upon:

- (1) adoption of a resolution or ordinance by the governing body complying with the requirements of Section 6-25-40 including publication of notice;
- (2) submission of an application to the joint system; and
- (3) approval of the application by resolution of the governing body of each member of the joint system except in the case of a joint system organized for the purpose of creating a financing pool, in which case the application must be approved by resolution of the commission.

(B) A member may withdraw from a joint system by resolution or ordinance of its governing body. A contractual right acquired or contractual obligation incurred by a member while it was a member remains in full force and effect after the member's withdrawal.

(C) Notice of a change in membership must be filed in the Office of the Secretary of State. No change is final until this filing occurs. The filing is not required if a joint system is organized only for the purpose of creating a financing pool.

(D) If a new member of the joint system is added hereunder, the approval documentation required under subsection (A)(3) above shall determine whether any new commissioners shall be added to the commission as necessary to support such new member of the joint system. If a new commissioner is added, ~~either~~ either by the member of the joint system or the Governor, as applicable, each such commissioner shall be appointed immediately.

**SECTION 5. Section 6-25-80 shall be amended and restated as follows:**

**§ 6-25-80.** Dissolution of system.

Whenever the commission of a joint system and the governing body of each of its members shall by resolution or ordinance determine that the purposes for which the joint system was formed have been substantially fulfilled and that all bonds issued and all other obligations incurred by the joint system have been fully paid or satisfied, the commission and members may declare the joint system to be dissolved. On the effective date of the resolution or ordinance, the title to all funds and other income and property owned by the joint system at the time of dissolution must be disbursed to the voting members of the joint system according to its bylaws.

*In the discretion of the members of a joint system for the proper and efficient operation of any joint system, an existing joint system may be reconstituted by following the procedures for the creation of a new joint system, mutatis mutandis.*

**SECTION 6. Section 6-25-110 shall be amended and restated as follows:**

**§ 6-25-110.** Authorization to incur debt and issue bonds.

A joint system may incur debt for any of its purposes and may issue bonds pledging to the payment as to both principal and interest the revenues, or any portion, derived or to be derived from all or any of its projects and any additions and betterments or extensions or contributions or advances from its members or other sources of funds available to it. A joint system may not undertake a project required to be financed, in whole or in part, with the proceeds of bonds without the approval of the governing bodies of each member which is obligated or to be obligated under any contract for the payment of amounts to be pledged as security therefore and a favorable vote of two-thirds of all commissioners. *Notwithstanding the foregoing, when a commission is appointed under Section 6-25-60(B)(2), no separate approval of the governing bodies of each member shall be required for the issuance of any bonds, and such bonds shall be authorized and approved by a simple majority of the commissioners. Any project may be preauthorized, preapproved or otherwise permitted under the terms of the project contract for the joint system, and such authority, approval or permission shall constitute all necessary approval of the respective governing bodies of each member herein.* A joint system formed only for the purpose of creating a financing pool may issue notes in anticipation of the issuance of bonds by its members to the government.

**SECTION 7. Section 6-25-128 shall be amended and restated as follows:**

**§ 6-25-128.** Contracts between authority and joint system; duration.

An authority may contract to buy from the joint system water required for its present or future requirements, including the capacity and output, or a portion or share of one or more specified projects. An authority also may contract for the collection or treatment of wastewater, including present or future capacity, or a portion or share of another project. The creation of a joint system is an alternative method whereby an authority may obtain the benefits and assume the responsibilities of ownership in a project, so a contract may provide that the authority forming the contract is obligated to make a payment required by the contract whether or not a project is completed, operable, or operating notwithstanding the suspension, interruption, interference, reduction, or curtailment of the output of a project or the water contracted for, and that the payments under the contract are not subject to reduction, whether by offset or otherwise, and are not conditioned upon the performance or nonperformance of the joint system or any other member of the joint system under the contract or any other instrument. A contract with respect to the sale or purchase of capacity or output, or a portion or share of them, of a project entered into between a joint system and its member authorities also may provide that if an authority or authorities default in the payment of its or their obligations with respect to the purchase of the capacity or output, or a portion or share of them, in that event the remaining member authorities which are purchasing capacity and output under the contract are required to accept and pay for and are entitled proportionately to and may use or otherwise dispose of the capacity or output which was to be purchased by the defaulting authority.

A contract concerning the sale or purchase of capacity and output from a project may extend for a period not exceeding fifty years from the date of the contract and may be renewable and extended upon terms as the parties may agree for not exceeding an additional fifty years; and the

execution and effectiveness is not subject to any authorizations or approvals by the State or any agency, commission, or instrumentality or political subdivision of them. Additionally, the contract may further provide that bonds or other indebtedness of the joint system may exceed the term of an initial or existing contract between or among the joint system and the respective members of the joint system, and in such event the contract, or at least the payment obligations of each member, shall be automatically extended to a period commensurate with the term of the bonds or other indebtedness.

Payments by an authority under a contract for the purchase of capacity and output from a joint system may be made from the revenues derived from the ownership and operation of the water system of the authority or from such other sources of funds as may be available, including any amounts received as payments in lieu of taxes. An authority may not pledge its full faith, credit, and taxing power to secure its obligations to the joint system or the bonds of the joint system. An authority is obligated to fix, charge, and collect rents, rates, fees, and charges for water or sewer services, facilities, and commodities sold, furnished, or supplied through its water or sewer system sufficient to provide revenues adequate to meet its obligations under any contract and to pay any and all other amounts payable from or constituting a charge and lien upon the revenues, including amounts sufficient to pay the principal of and interest on general obligation bonds, if any, heretofore or hereafter issued by the authority for purposes related to its water or sewer system.

An authority that is a member of a joint system may furnish the joint system with money derived from the ownership and operation of its water or sewer system or facilities and provide the joint system with personnel, equipment, and property, both real and personal, and from any other sources legally available to it for such purposes. An authority also may provide services to a joint system.

A member of a joint system may contract for, advance, or contribute funds derived from the ownership and operation of its water or sewer system or facilities or from another legal source to a joint system as agreed upon by the joint system and the member, and the joint system shall repay the advances or contributions from the proceeds of bonds, operating revenue, or other funds of the joint system, together with interest as agreed upon by the member and the joint system.

**SECTION 8. This act takes effect upon approval by the Governor.**

<b>Summary report:</b>	
<b>Litera Compare for Word 11.10.0.38 Document comparison done on 6/11/2025 6:45:02 AM</b>	
<b>Style name:</b> Default Style	
<b>Intelligent Table Comparison:</b> Active	
<b>Original DMS:</b> nd://4921-7418-3472/2/Legislation - Title 6 Chapter 25 (Revised).doc	
<b>Modified DMS:</b> nd://4921-7418-3472/3/Legislation - Title 6 Chapter 25 (Revised).doc	
<b>Changes:</b>	
<u>Add</u>	11
<del>Delete</del>	13
<del>Move From</del>	0
<u>Move To</u>	0
<u>Table Insert</u>	0
<del>Table Delete</del>	0
<u>Table moves to</u>	0
<del>Table moves from</del>	0
Embedded Graphics (Visio, ChemDraw, Images etc.)	0
Embedded Excel	0
Format changes	0
<b>Total Changes:</b>	<b>24</b>

Meeting minutes not included in this version of the report but are available at <https://ojrsa.org/wp-content/uploads/Recommendations-2025-6-15-FINAL-includes-all-meeting-minutes.pdf> or [www.ojrsa.org/info](http://www.ojrsa.org/info). These links include access to the full report and attachments, including meeting minutes, as accepted by the OJRSA Board of Commissioners at its July 15, 2025 called meeting.

Sample resolution from Lawrence Flynn

**A RESOLUTION ACKNOWLEDGING RECEIPT OF, AND EXPRESSING SUPPORT FOR, THE IMPLEMENTATION OF THE RECOMMENDATIONS OF THE AD HOC REGIONAL FEASIBILITY STUDY IMPLEMENTATION COMMITTEE; AND OTHER MATTERS RELATED THERETO.**

**NOW THEREFORE**, be it resolved by the City Council of the City of Westminster (the “**City Council**”), the governing body of the City of Westminster, South Carolina (the “**City**”), as follows:

**Section 1 Findings.** The City Council make the following findings in connection with the adoption of this resolution (this “**Resolution**”):

A. The City is a municipal corporation of the State of South Carolina (the “**State**”) located in Oconee County, South Carolina, and as such possesses all general powers granted by the Constitution and statutes of the State to such public entities.

B. The City is a member of Oconee Joint Regional Sewer Authority (“**OJRSA**”), a joint authority sewer system organized under Title 6, Chapter 25 of the Code of Laws of South Carolina 1976, as amended (the “**Act**”), created in 2007 by its three member-municipalities: the City of Seneca, South Carolina (“**Seneca**”), the City of Walhalla, South Carolina (“**Walhalla**”), and the City (collectively, the “**Members**”).

C. OJRSA commissioned the Regional Feasibility Planning Study (“**Planning Study**”), which was completed in August 2024 and formally adopted by the Board of Commissioners, as the governing body of OJRSA (“**Board**”) in September 2024.

D. The Planning Study recommended the formation of an Ad Hoc Regional Feasibility Study Implementation Committee (“**Ad Hoc Committee**”) to further evaluate and develop implementation strategies to restructure OJRSA.

E. The Board established the Ad Hoc Committee in November 2024, who convened regularly from December 2024 through June 2025 to conduct a comprehensive review of the Planning Study and develop independent recommendations for implementation.

F. The City’s representative, Mr. Scott Parris, served as a member of the Ad Hoc Committee throughout its deliberations.

G. On June 16, 2025, the Ad Hoc Committee issued a final report entitled “OJRSA Reorganization Recommendations” that includes five major recommendations for the reorganization and reconstitution of OJRSA under the Act (the “**Recommendation Report**”).

H. The recommendations are intended to address longstanding operational, governance, regulatory, and financial challenges facing OJRSA and the Members, and to provide for a coordinated, compliant, and sustainable regional wastewater system to serve the current and future needs of Oconee County and its municipalities.

I. The City Council has received and reviewed the Recommendation Report, including the proposed implementation timeline, and recognizes the importance of working cooperatively and in good faith with OJRSA, Seneca, Walhalla, Oconee County, and other stakeholders to advance the implementation of the recommendations therein.

**Section 2 Support for Implementation.** The City expresses its support for the recommendations contained in the Recommendation Report and agrees to work in good faith with OJRSA, the other Members, Oconee County, and other affected entities to evaluate and, where appropriate, implement the proposed actions, including but not limited to: (i) the consolidation of Members’ sewer collection systems, including the City’s system, and enforced compliance of all applicable sewer user regulations; (ii) the development of a reconstituted governance structure for OJRSA, including the elimination of ex officio, principal-agent or other potentially conflicted members; (iii) the drafting of new governance documents; (iv) participation in the formation of an implementation committee to shepherd the reorganization process; and (v) the use of a coordinated communications plan to support public engagement and transparency. In addition to its confirmation and support of the major recommendations of the Recommendation Report, the City further supports and agrees that changes to the Act are needed and necessary to fully formulate the terms and findings of the Recommendation Report. Finally, the City Council will act in good faith to assure the City’s compliance with the timeline for implementation of the Recommendation Report, including the engagement of all necessary consultants and other personnel necessary to formalize the planned restructuring.

**Section 3 Non-Binding Intent.** This Resolution expresses the City’s non-binding intent to proceed in good faith with the evaluation and implementation process, with the understanding that final approvals of any restructuring or system consolidation actions will remain subject to the review and approval of City Council based on mutually agreed-upon terms and conditions.

**Section 4 Further Action; Effective Date.** The City Administrator is hereby directed to deliver this Resolution to OJRSA and any State regulatory agencies or entities in order to evidence the City’s initial approval of the Recommendation Report. This Resolution shall become effective immediately upon its adoption.

DONE AND ADOPTED, this \_\_\_\_ th day of \_\_\_\_\_ 2025.

CITY OF WESTMINSTER, SOUTH CAROLINA

\_\_\_\_\_  
Mayor

(SEAL)

ATTEST:

\_\_\_\_\_  
City Clerk



## “OJRSA Reorganization Recommendations” Exhibit A Timeline

Task	Target Schedule for Completion*	Target Date
Current Board will dissolve the current Ad Hoc Committee and establish the Implementation Committee (“Reconstitution Committee”) for further implementation oversight.	45 days	8/29/2025
Legislative revisions to the Joint Authority Water and Sewer Systems Act (“Act”) will be finalized and provided to the Oconee County Delegation. Consultation shall be made with the Delegation on whether lobbyist support will be needed.	45 days	8/29/2025
Reconstitution Committee will provide <u>quarterly updates</u> to the SCRIA, the current Board, and Oconee County on the progress of the implementation of the initial recommendations.	Quarterly	9/30/2025
Resolutions of support for consolidation/OJRSA reorganization will be provided to and adopted by each governing body affected by the recommendation, including: OJRSA, Seneca, Walhalla, Westminster, West Union, & Oconee County.	90 days	10/13/2025
Consultants shall be engaged and the process of collection system <u>technical evaluation</u> and <u>financial valuation</u> will be initiated, including the identification of potential funding for effort and immediate rehabilitation projects that may be identified or current CIP. Additionally, a <u>rate consultant</u> will be engaged.	120 days	11/12/2025
Communication plan to be developed under the guidance of the Reconstitution Committee and provided to all entities involved.	120 days	11/12/2025
List of recommendations for the initial commissioners for the New Commission will be provided to Delegation.	Within 60 days of Approved Changes to Act <sup>†</sup>	8/1/2026
Complete the technical evaluation and financial valuation of the collection systems.	15 months after beginning process	2/27/2027
Unified, equitable rate structure timeline will be provided as part of initial terms for collection system consolidation.	18 months after beginning process	5/12/2027
Legal documents to transfer collection system assets to OJRSA to be executed, as well as all necessary reconstitution documents.	24 months after beginning process	7/15/2027
If the legislative amendments have not be approved, plans for consolidation under the amended Act will be abandoned. Thereupon, the OJRSA will proceed to consolidate the member system and implement the reconstitution under the existing Act, with such process to be finalized by no later than 36 months. Additionally, all members shall be issued permits in compliance with the OJRSA Sewer Use Regulation and added as co-permittees under the NPDES permit, if consolidation for any member does not occur.	25 months after beginning process	8/16/2027

\* As noted in Exhibit A of the “OJRSA Reorganization Recommendations,” the implementation schedule is to begin when the OJRSA Board of Commissioners accepted the report its July 15, 2025 called meeting.

<sup>†</sup> Estimated to be July/August 2026.

TO AMEND CERTAIN PROVISIONS OF TITLE 6, CHAPTER 25 OF THE CODE OF LAWS OF SOUTH CAROLINA 1976, TO AUTHORIZE CERTAIN CLARYIFYING AMENDMENTS REGARDING COMMISSIONERS, RECONSTITUTION, BOND APPROVAL AND DURATION.

Be it enacted by the General Assembly of the State of South Carolina:

**SECTION 1. Section 6-25-20 shall be amended to add the following defined terms:**

**§ 6-25-20. Definitions.**

(14) "Legislative Delegation" means all members of the South Carolina Senate and South Carolina House representing any county where a joint system is located.

(15) "Governor" means the Governor of the State of South Carolina.

**SECTION 2. Section 6-25-50 shall be amended and restated as follows:**

**§ 6-25-50.** ~~Agreement as to number of commissioners each member may appoint;~~ Application filed with Secretary of State; corporate certificate.

(A) The governing bodies of the members of a joint system shall form an agreement specifying the number of commissioners ~~each member may appoint to a commission created to govern the joint system pursuant to Section 6-25-60.~~

(B) ~~Two or more commissioners~~ The proposed members of a joint system shall jointly file an application with the Secretary of State ~~an application signed by the commissioner or each proposed member setting forth:~~

(1) ~~the names of~~ number of proposed members of the joint system, the number of proposed commissioners, and their respective appointed commissioners the method of appointment pursuant to Section 6-25-60(B);

(2) ~~(a) the a~~ certified copy of a resolution of each member determining it is in its best interest to participate in the proposed joint system; ~~and~~

~~(b) the resolution appointing the member's commissioner;~~

(3) the desire that the joint system be organized as a public body corporate and politic under this chapter;

(4) the name which is proposed for the joint system; and

(5) the purpose for creation of the joint system.

The Secretary of State shall file the application if after examining it and determining that it complies with the requirements in this section and that the proposed name of the joint system is not identical with that of any other corporation of the State or any agency or instrumentality or so nearly similar as to lead to confusion and uncertainty.

After the application has been filed, the Secretary of State shall issue a corporate certificate that must be filed with the application, and the joint system then must be constituted a public body corporate and politic under the name proposed in the application. The corporate certificate shall set forth ~~the names of all voting member~~ and the name of the joint system. There also must be stated upon the corporate certificate the purpose for which it has been created, as set forth in the application. Notice of the issuance of such corporate certificate must be given to all members of the joint system by the Secretary of State.

In any suit, action, or proceeding involving the validity or enforcement of, or relating to, contract of a joint system, the joint system in the absence of establishing fraud shall be conclusively

considered to have been established in accordance with the provisions of this chapter upon proof of the issuance of the certificate by the Secretary of State. A copy of the certificate, duly certified by the Secretary of State, is admissible in evidence in any suit, action, or proceeding and is conclusive proof of the filing and contents.

**SECTION 3. Section 6-25-60 shall be amended and restated as follows:**

§ 6-25-60. Joint system to be managed and controlled by commission; appointment of commissioners; oath; records; seal; quorum; vacancies; expenses.

(A) The management and control of a joint system is vested in a commission that may consist of no fewer than five members and no more than eleven members. A commissioner has one vote and may have additional votes as a majority of the members of the joint system determines. Notwithstanding the provisions of this subsection requiring the commission managing a joint system to have no fewer than five members and no more than eleven members, a joint system in existence on this section's effective date and having fewer than five members or more than eleven members on this section's effective date may continue to maintain the number of members serving on the section's effective date and may add additional members as its commissioners determine.

(B) As contemplated by the initial application to the Secretary of State, commissioners serving on the commission may be appointed under one of the following procedures:

(1) Appointment by member. The governing body of each voting member of a joint system shall appoint one or more a commissioner~~s~~, pursuant to ~~Section 6-25-50(A)~~, to serve as a commissioner of the joint system. ~~A commissioner has one vote and may have additional votes as a majority of the members of the joint system determines.~~ A commissioner serves at the pleasure of the governing body by which he was appointed. A commissioner, before entering upon his duties, shall take and subscribe to an oath before a person authorized by law to administer oaths to execute the duties of his office faithfully and impartially, and a record of each oath must be filed with the governing body of the appointing authority.

~~Notwithstanding the provisions of this subsection requiring the commission managing a joint system to have no fewer than five members and no more than eleven members, a joint system in existence on this section's effective date and having fewer than five members or more than eleven members on this section's effective date may continue to maintain the number of members serving on the section's effective date and may add additional members as its commissioners determine.~~ Further, and notwithstanding the appointment requirements above, in the event there are an even number of members of a joint system (i.e. 4, 6, 8, 10), the project contract, bylaws or other similar agreement for the joint system may authorize one additional member of the commission; such additional commissioner shall be recommended by the legislative delegation from each county where the joint system is located, and upon receipt of such recommendation, such additional commissioner shall appointed by the Governor. Any gubernatorial appointment shall be for a term of four years and shall serve until a duly appointed successor is appointed and qualified. Any commissioner appointed by the Governor hereunder must reside within a household receiving utility services from the joint system or a member of the joint system. Any vacancy of such member must be filled for the remainder of the unexpired term in the same manner as the original appointment. If a new member of a joint system is added under the provisions hereof such that there becomes an odd number of members of a joint system, any gubernatorial appointed commissioner shall be deemed to automatically vacate his position as a commissioner as of the date of the admission of such new member of a joint system and their respective appointment of a new commissioner.

(2) Appointment by Governor. The commissioners may be appointed by the Governor in accordance with the following procedures:

(a) The Governor, based upon the recommendation of the legislative delegation from each county that the joint system operates, shall appoint each commissioner. Each appointed commissioner must reside within a household receiving utility services from the joint system or a member of the joint system. In making such appointments, there shall be at least one commissioner appointed by the Governor from the service area of each member of the joint system.

(b) Excepting the initial appointments as necessary to create a staggered commission which may be two or four years, respectively, each commissioner must be appointed and serve for a term of four years and until his successor is appointed and qualified, provided that the terms of the commissioners must be staggered such that approximately one-half of the total members appointed by the Governor must be appointed or reappointed every two years. A vacancy must be filled for the remainder of the unexpired term in the manner of the original appointment. Respecting the initial commission appointed herein, the minority portion of the staggered membership, representing those authorities with the lowest number of customers of the joint system, shall serve for an initial two-year term.

~~(B)~~ (C) The commissioners of the joint system shall annually, or biennially, if provided in the bylaws of the joint system, elect, with each commissioner having one vote, one of the commissioners as chairman, another as vice chairman, and other persons who may, but need not be commissioners, as treasurer, secretary and, if desired, assistant secretary. The office of treasurer may be held by the secretary or assistant secretary. The commission may also appoint such additional officers as it deems necessary. The secretary or assistant secretary of the joint system shall keep a record of the proceedings of the joint system, and the secretary must be the custodian of all books, records, documents, and papers filed with the joint system, the minute book or journal of the joint system, and its official seal.

~~(C)~~ (D) A majority of the commissioners of the joint system shall constitute a quorum. A vacancy on the commission of the joint system shall not impair the right of a quorum to exercise all rights and perform all the duties of a joint system. Any action taken by the joint system under the provisions of this chapter may be authorized by resolution at any regular or special meeting held pursuant to notice in accordance with bylaws of the joint system, and each resolution shall take effect immediately and need not be published or posted. Except as is otherwise provided in this chapter or in the bylaws of the joint system, a majority of the votes which the commissioners present are entitled to cast, with a quorum present, shall be necessary and sufficient to take any action or to pass any resolution. No commissioner of a joint system shall receive any compensation solely for the performance of duties as a commissioner, but each commissioner may be paid per diem, mileage, and subsistence expenses, as provided by law for state boards, committees, and commissions, incurred while engaged in the performance of such duties.

(E) All commissioners shall hold the qualifications of an elector.

(F) Commissioners appointed under subsection (B)(2) above may not be an officer or employee of a member of a joint system, and no commissioner shall be permitted to serve on an ex officio basis. Separately, for commissioners appointed under subsection (B)(1) above, the members of the joint system may include a restriction in the project contract, bylaws or other agreement for the joint system that no commissioner may be an officer or employee of a member of a joint system, and no commissioner shall be permitted to serve on an ex officio basis.

(G) Any commissioner appointed hereunder shall be deemed to forfeit his respective position if such person (1) lacks, at any time during his term of office, any qualifications for the office prescribed by general law and the Constitution, or (2) is convicted of any crime, other than civil infractions or misdemeanors for which no imprisonment is imposed.

**SECTION 4. Section 6-25-70 shall be amended and restated as follows:****SECTION 6-25-70.** Change in membership of joint system.

(A) After the creation of a joint system, any other authority may become a member *of the joint system* upon:

(1) adoption of a resolution or ordinance by the governing body complying with the requirements of Section 6-25-40 including publication of notice;

(2) submission of an application to the joint system; and

(3) approval of the application by resolution of the governing body of each member of the joint system except in the case of a joint system organized for the purpose of creating a financing pool, in which case the application must be approved by resolution of the commission.

(B) A member may withdraw from a joint system by resolution or ordinance of its governing body. A contractual right acquired or contractual obligation incurred by a member while it was a member remains in full force and effect after the member's withdrawal.

(C) Notice of a change in membership must be filed in the Office of the Secretary of State. No change is final until this filing occurs. The filing is not required if a joint system is organized only for the purpose of creating a financing pool.

(D) If a new member of the joint system is added hereunder, the approval documentation required under subsection (A)(3) above shall determine whether any new commissioners shall be added to the commission as necessary to support such new member of the joint system. If a new commissioner is added, either by the member of the joint system or the Governor, as applicable, each such commissioner shall be appointed immediately.

**SECTION 5. Section 6-25-80 shall be amended and restated as follows:****§ 6-25-80.** Dissolution of system.

Whenever the commission of a joint system and the governing body of each of its members shall by resolution or ordinance determine that the purposes for which the joint system was formed have been substantially fulfilled and that all bonds issued and all other obligations incurred by the joint system have been fully paid or satisfied, the commission and members may declare the joint system to be dissolved. On the effective date of the resolution or ordinance, the title to all funds and other income and property owned by the joint system at the time of dissolution must be disbursed to the voting members of the joint system according to its bylaws.

In the discretion of the members of a joint system for the proper and efficient operation of any joint system, an existing joint system may be reconstituted by following the procedures for the creation of a new joint system, mutatis mutandis.

**SECTION 6. Section 6-25-110 shall be amended and restated as follows:****§ 6-25-110.** Authorization to incur debt and issue bonds.

A joint system may incur debt for any of its purposes and may issue bonds pledging to the payment as to both principal and interest the revenues, or any portion, derived or to be derived from all or any of its projects and any additions and betterments or extensions or contributions or advances from its members or other sources of funds available to it. A joint system may not undertake a project required to be financed, in whole or in part, with the proceeds of bonds without the approval of the governing bodies of each member which is obligated or to be obligated under any contract for the payment of amounts to be pledged as security therefore and a favorable vote of two-thirds of all commissioners. Notwithstanding the foregoing, when a commission is

appointed under Section 6-25-60(B)(2), no separate approval of the governing bodies of each member shall be required for the issuance of any bonds, and such bonds shall be authorized and approved by a simple majority of the commissioners. Any project may be preauthorized, preapproved or otherwise permitted under the terms of the project contract for the joint system, and such authority, approval or permission shall constitute all necessary approval of the respective governing bodies of each member herein. A joint system formed only for the purpose of creating a financing pool may issue notes in anticipation of the issuance of bonds by its members to the government.

**SECTION 7. Section 6-25-128 shall be amended and restated as follows:**

**§ 6-25-128.** Contracts between authority and joint system; duration.

An authority may contract to buy from the joint system water required for its present or future requirements, including the capacity and output, or a portion or share of one or more specified projects. An authority also may contract for the collection or treatment of wastewater, including present or future capacity, or a portion or share of another project. The creation of a joint system is an alternative method whereby an authority may obtain the benefits and assume the responsibilities of ownership in a project, so a contract may provide that the authority forming the contract is obligated to make a payment required by the contract whether or not a project is completed, operable, or operating notwithstanding the suspension, interruption, interference, reduction, or curtailment of the output of a project or the water contracted for, and that the payments under the contract are not subject to reduction, whether by offset or otherwise, and are not conditioned upon the performance or nonperformance of the joint system or any other member of the joint system under the contract or any other instrument. A contract with respect to the sale or purchase of capacity or output, or a portion or share of them, of a project entered into between a joint system and its member authorities also may provide that if an authority or authorities default in the payment of its or their obligations with respect to the purchase of the capacity or output, or a portion or share of them, in that event the remaining member authorities which are purchasing capacity and output under the contract are required to accept and pay for and are entitled proportionately to and may use or otherwise dispose of the capacity or output which was to be purchased by the defaulting authority.

A contract concerning the sale or purchase of capacity and output from a project may extend for a period not exceeding fifty years from the date of the contract and may be renewable and extended upon terms as the parties may agree for not exceeding an additional fifty years; and the execution and effectiveness is not subject to any authorizations or approvals by the State or any agency, commission, or instrumentality or political subdivision of them. Additionally, the contract may further provide that bonds or other indebtedness of the joint system may exceed the term of an initial or existing contract between or among the joint system and the respective members of the joint system, and in such event the contract, or at least the payment obligations of each member, shall be automatically extended to a period commensurate with the term of the bonds or other indebtedness.

Payments by an authority under a contract for the purchase of capacity and output from a joint system may be made from the revenues derived from the ownership and operation of the water system of the authority or from such other sources of funds as may be available, including any amounts received as payments in lieu of taxes. An authority may not pledge its full faith, credit, and taxing power to secure its obligations to the joint system or the bonds of the joint system. An authority is obligated to fix, charge, and collect rents, rates, fees, and charges for water or sewer services, facilities, and commodities sold, furnished, or supplied through its water or sewer system sufficient to provide revenues adequate to meet its obligations under any contract and to pay any

and all other amounts payable from or constituting a charge and lien upon the revenues, including amounts sufficient to pay the principal of and interest on general obligation bonds, if any, heretofore or hereafter issued by the authority for purposes related to its water or sewer system.

An authority that is a member of a joint system may furnish the joint system with money derived from the ownership and operation of its water or sewer system or facilities and provide the joint system with personnel, equipment, and property, both real and personal, and from any other sources legally available to it for such purposes. An authority also may provide services to a joint system.

A member of a joint system may contract for, advance, or contribute funds derived from the ownership and operation of its water or sewer system or facilities or from another legal source to a joint system as agreed upon by the joint system and the member, and the joint system shall repay the advances or contributions from the proceeds of bonds, operating revenue, or other funds of the joint system, together with interest as agreed upon by the member and the joint system.

**SECTION 8. This act takes effect upon approval by the Governor.**



## OCONEE JOINT REGIONAL SEWER AUTHORITY

### Operations & Planning Committee

August 20, 2025

The Operations & Planning Committee meeting was held at the Coneross Creek Wastewater Treatment Plant.

Commissioners that were present:

- Seat 2 (Seneca): Scott Moulder (Committee Chairman)
- Seat 3 (Seneca): Scott McLane
- Seat 9 (Walhalla & Westminster): David Dial

Commissioners that were not present:

- Seat 6 (Walhalla): Vacant Until New Committee Member Appointed

OJRSA appointments and staff present were:

- Lynn Stephens, Secretary/Treasurer to the Board and Office Manager
- Chris Eleazer, Executive Director

Others present were:

- None

**A) Call to Order** - Mr. Moulder called the meeting to order at 8:30 a.m.

**B) Public Session** – None. Mr. Moulder took a moment to say he appreciates being on this committee and serving as chairman on it.

**C) Presentation and Discussion Items:**

**1. Update on Current Projects (Exhibit A)** – Mr. Eleazer highlighted the following items on the list:

Item #17 – This is a package that has been advertised for bids and will be for replacement of a lot of equipment. Mr. Eleazer stated that OJRSA Operations Director, Mr. Kyle Lindsay, is planning on procuring much of it internally and then someone will come in and install it.

Mr. Dial said there was no amount for this item and asked if the OJRSA had an idea of the cost. Mr. Eleazer replied the OJRSA has an estimated cost that was used for budgeting purposes; however, it is not being advertised, because advertising for this project went out Wednesday or Thursday of last week in the newspaper and through the SC Business Opportunities website, and everyone that will submit bids would use that estimate. The Director added that Mr. Lindsay will have a mandatory pre-bid meeting where he will show everyone what needs to be done and give them the opportunity to ask questions.

Item #5 “Indefinite Delivery Contract for Engineering Services” – Mr. Eleazer said the Procurement Policy allows the OJRSA to solicit for standby/on-call services. It is in legal review right now before being advertised. The OJRSA is looking at having two (2) engineering firms to do basic engineering services (design pump stations, force mains, gravity sewer, rehabilitation, plan review, etc.).

Item #7 – The OJRSA received eight (8) submittals for the CMMS software system upgrade which closed out on August 14, 2025. The review process is starting and will hopefully be done by the middle of next week and then three (3) demos will be scheduled. This will allow the OJRSA to move into true asset management and tracking of costs. Mr. Eleazer added that this will be tied to the

ArcGIS (ESRI system). The Director also stated that once a CMMS system has been selected, the OJRSA will move forward with finding a new financial system that will integrate with the CMMS.

- 2. Richland Creek Gravity Sewer Expansion** – The Director distributed a handout to the committee (*made a part of these minutes*). He said this would qualify to be an impact fee project. There is no cost estimate for this project, and it could be done as a whole or in phases.

The current trunk sewer line goes up to Sandifer Blvd./Highway 123/Highway 76. The new Target development will be located to the northeast corner of the map near the golf course. There has been discussion for years (even before Mr. Eleazer's time at the OJRSA) to extend the gravity sewer along Richland Creek and up to Blue Ridge Boulevard to eliminate the Halfway Branch Pump Station. This will fix numerous problems that the OJRSA and Seneca Light & Water have regarding capacity issues.

Mr. Eleazer added that Halfway Branch Pump Station wastewater currently flows through the western part of the city and through the Cross Creek Golf Course (where there have been several overflows in the past six (6) months). Between conversations with Mr. McLane and the consulting engineers, this has always been an area that has been identified as needing attention. It would be beneficial to take the flow from Halfway Branch and move it to the trunk gravity sewer that flows to the treatment plant from the west (he pointed to the Coneross Creek Trunk Sewer). That would serve a dual purpose: to allow sewer availability in an area that is in tremendous demand and to help Seneca Light & Water with its capacity issues at the SNS South Pump Station. Mr. McLane added that it would open a lot of doors, including bringing their Cliffabee Leas Pump Station flow down to Sheep Farm Road.

The Director said the Thornwell Property project is titled "Phase I." There obviously is another "Phase II" project planned for the future, but there is no capacity remaining in the sewer system for a "Phase II" without infrastructure improvements on Seneca's and the OJRSA's systems. The OJRSA is going to have to replace the line over the railroad bridge on Highway 123 near Sealed Air to be able to accommodate flow that way. Mr. Eleazer explained how he didn't think SCDOT would let the OJRSA replace the pipe going across the bridge with a bigger pipe.

Mr. McLane explained how Seneca Light & Water's original plan was to eliminate the SNS South, Walmart, and Sheep Farm Road pump stations, and then add Cliffabee Leas and eliminate that pump station.

Mr. Eleazer asked the committee members if they were interested in looking further at this. All the committee members were interested in looking at it further, and Mr. Moulder added that it would benefit all three (3) Member Cities.

#### **D) Action Items to Recommend to the Board for Consideration:**

- **Consider Moving the Date or Time for the Operations & Planning Committee Meetings** – Mr. Moulder explained to the committee members that Wednesday mornings are extremely busy for him between meeting with the mayor, staff meetings, and a weekly radio show. He requested to move this meeting from Wednesday to a Thursday or Tuesday.

Mr. Eleazer added that he checked with OJRSA Attorney, Mr. Lawrence Flynn, to see if there were any legal conflicts with changing the date and time of the committee meeting, and there was nothing in the bylaws to prevent it.

***Mr. Moulder made a motion, seconded by Mr. McLane, to move the Operations and Planning Committee meetings to the third Thursday of each month at 8:30 a.m. The motion carried.***

#### **E) Executive Director's Discussion and Compliance Matters** – The Executive Director reported on the following:

- 1. Environmental and Regulatory Compliance** – The OJRSA is still awaiting a response from the SC Department of Environmental Services (SCDES) regarding the OJRSA's NPDES permit. The OJRSA submitted a response to them but has not heard back since. Mr. Eleazer added that the new wastewater treatment with peracetic acid (PAA) is tied to this permit.

**2. Miscellaneous (If Any) – None.**

**F) Committee Members' Discussion – None.**

**G) Upcoming Meetings:**

- 1. Finance & Administrative Committee – Tuesday, August 26, 2025 at 9:00 a.m.**
- 2. Board of Commissioners – Monday, September 8, 2025 at 4:00 p.m.**
- 3. Ad-Hoc Reconstitution Committee – Thursday, September 11, 2025 at 9:00 a.m.**
- 4. Operations & Planning Committee – Thursday, September 18, 2025 at 8:30 a.m.**

**H) Adjourn – The meeting adjourned at 8:53 a.m.**

Notification of the meeting was distributed on August 1st and 8th, 2025 to *Upstate Today*, *Anderson Independent-Mail*, *Westminster News*, *Keowee Courier*, WGOG Radio, WSNW Radio, City of Seneca Council, City of Walhalla Council, City of Westminster Council, Oconee County Council, SC DHEC, [www.ojrsa.org](http://www.ojrsa.org), and posted at the OJRSA Administration Building.



## Operations & Planning Committee Meeting

OJRSA Operations & Administration Building

Lamar Bailes Board Room

August 20, 2025 at 8:30 AM

*OJRSA commission and committee meetings may be attended in person at the address listed above. The OJRSA will also broadcast meetings live on its YouTube channel at [www.youtube.com/@OconeeJRSA](http://www.youtube.com/@OconeeJRSA) (if there is a technical issue preventing the livestreaming of the meeting, then a recording will be published on the channel as soon as possible). For those not able to attend in person, then the OJRSA Board or Committee Chair will accept public comments by mail (623 Return Church Rd, Seneca, SC 29678) or at [info@ojrsa.org](mailto:info@ojrsa.org). Comments must comply with the public session instructions as stated on the meeting agenda and will be received up until one hour prior to the scheduled meeting. If there is not a public session scheduled for a meeting, then comments shall not be accepted.*

### Agenda

- A. Call to Order** – Scott Moulder, Committee Chair
- B. Public Session** – Receive comments relating to topics on this agenda. Session is limited to a maximum of 30 minutes with no more than 5 minutes per speaker.
- C. Presentation and Discussion Items** *[May include vote and/or action on matters brought up for discussion]*
  - 1. Update on current projects (Exhibit A) – Chris Eleazer, Director
  - 2. Richland Creek gravity sewer expansion – Chris Eleazer, Director
- D. Action Items to Recommend to the Board for Consideration**
  - Consider moving the date or time for the Operations & Planning Committee meetings – Scott Moulder, Committee Chair
- E. Executive Director’s Discussion and Compliance Matters** – Chris Eleazer, Director
  - 1. Environmental and regulatory compliance matters
  - 2. Miscellaneous *(if any)*
- F. Committee Members’ Discussion** – Led by Scott Moulder, Committee Chair  
Discussion can be related to matters addressed in this meeting or for future consideration by the Board or Committee. Voting is not permitted during this session.
- G. Upcoming Meetings** *All meetings to be held in the OJRSA Lamar Bailes Board Room unless noted otherwise.*
  - 1. Finance & Administration Committee – August 26, 2025 at 9:00 AM
  - 2. Board of Commissioners – September 8, 2025 at 4:00 PM
  - 3. Ad Hoc Reconstitution Committee – September 11, 2025 at 9:00 AM
  - 4. Operations & Planning Committee – *To be considered at meeting*
- H. Adjourn**

FY2026 O&M FUND PROJECTS

CONSENT ORDER ENGINEERING AND OPERATIONS AND MAINTENANCE TASKS

Row #	FY 2026 O&M Project (Project # (if applicable); PM) CANNOT CARRY OVER TO NEXT FISCAL YEAR WITHOUT BUDGET APPROVAL	Approx % Complete	Anticipated Completion	PO/Contract Amount (\$)	O&M PROJECT MILESTONES				Obligated/ Spent (\$)	Budget Remaining (\$)	GL Code (XXXXX = get from Office Mgr)	Comp. Performing (and Project Mgr)	
					Bids/RFQ/etc. Issue/Advertised	Req/Contract Signed	Started Work	Completed					
1	<b>Consent Order 21-025-W Project:</b> Biannual Compliance Report (CE)	0%	11/8/2025	0	Internal Project	Internal Project	N/A		0	0	N/A	OJRSA Chris Eleazer	
2	Agency Reconstitution (Sewer Feasibility Implementation) (Board, Others)	0%	TBD	N/A	See below	See below	7/15/2025		0	0	N/A	Board of Commissioners	
3	Completion of Development Guide (AM)	5%	12/31/2025	N/A	Internal Project	Internal Project	9/10/2024		0	0	N/A	OJRSA Chris Eleazer	
4	Development Policy Revision (CE)	70%	10/6/2025	N/A	Internal Project	Internal Project	9/24/2024		0	0	N/A	OJRSA Chris Eleazer	
5	Indefinite Delivery Contract for Engineering Services (CE)	50%	10/6/2025	N/A	In legal review b/f issue				0	0	N/A	OJRSA Chris Eleazer	
6	Arc Flash 70E Assessment of WRF, PSs, and Other Facilities (AM)	0%	10/31/2025	12,650	Prof Svcs	8/12/2025			0	12,650	Admin: Safety 501-02370	Life & Safety TBD	
7	CMMS & Financial Software System Upgrade (CE)	2%	6/30/2026	TBD	7/3/2025				0	0	Admin Services 501-02420	TBD	
8	Comprehensive Sewer Management Plan <b>Project #2026-04</b> (KL)	0%	TBD	TBD	Proj #2026-04 Prof Svcs				0	0	Con Sys: Prof Svcs 601-02430	TBD	
9	Evaluate Perkins PS & Coneross PS Pumps to Determine Repair vs. Replace (KL, EP)	0%	10/1/2025	TBD	IDC Engineer				0	0	Con Sys: Prof Svcs 601-02430	TBD	
10	Hydraulic Model/Field Data Collection (CE)	5%	12/31/2025	TBD	Prof Svcs				0	0	Con Sys: Prof Svcs 601-02430	GMC Hannah Ribelin	
11	Coneross PS Rotating Assembly for Pumps #4 & #5 (EP)	0%	TBD	TBD					0	0	Con Sys: R&M COS-PS 601-05030	TBD	
12	Martin PS Motor Base Restraint System (#2 of 3) (EP)	0%	12/30/2025	35,753	Sole Source 8/4/2025				35,753	0	Conv Sys R&M: MAS2-PS 601-05100	TBD	
13	Martin PS Aeration Motor Install (crane needed) (EP)	0%	11/30/2025	TBD					0	0	Conv Sys: Equip Rent 601-02540	TBD	
14	NPDES Permit Renewal, Including PAA Installation and Operation (JM, KL)	0%	10/31/2025	3,500	NPDES: 4/19/22 PAA: 4/1/22	NPDES: 8/22/22 PAA: 8/1/22	NPDES: 7/1/22 PAA: 8/2/22	NPDES: ___ PAA: ___	0	3,500	WRF: Prof Svcs 701-02430	Goldie Assoc Paul Lewis	
15	<b>CIP PRIORITY 1A:</b> Portable Generator Connection for WRF (includes engineering) (JM, KL)	0%	3/31/2026	TBD					0	0	WRF: R&M 701-03000	TBD	
16	Headworks Flow Pulse and Flow Channel Sensor Install (JM)	0%	8/30/2025	TBD	8/4/2025				0	0	WRF: R&M 701-03000	TBD	
17	Project #2026-02 General Water Reclamation Facility Installation Projects <i>See below</i> (JM, KL)	1%	5/31/2026	TBD	8/13/2025				0	0	WRF: R&M 701-03000	TBD	
	<b>CIP PRIORITY 1A:</b> Primary Clarifier Sludge Pump Replacement and Installation	0%	TBD	See Row 17 Above	See Row 17 Above	See Row 17 Above			0	0	See Row 14 Above	See Row 14 Above	
	<b>CIP PRIORITY 2:</b> Primary Clarifier #2 Scum Pump Replacement (one in FY26, one in FY27)	0%	TBD	See Row 17 Above	See Row 17 Above	See Row 17 Above			0	0	See Row 14 Above	See Row 14 Above	
	Aeration 10" Mag Meter Installation	0%	TBD	See Row 17 Above	See Row 17 Above	See Row 17 Above			0	0	See Row 14 Above	See Row 14 Above	
	<b>CIP PRIORITY 1A:</b> Aeration Gate Replacement	0%	TBD	See Row 17 Above	See Row 17 Above	See Row 17 Above			0	0	See Row 14 Above	See Row 14 Above	
	<b>CIP PRIORITY 1A:</b> Aeration Motor Repair/ Replacement	0%	TBD	See Row 17 Above	See Row 17 Above	See Row 17 Above			0	0	See Row 14 Above	See Row 14 Above	
	Biological Reactor Basin Oxid Motor Replacement	0%	TBD	See Row 17 Above	See Row 17 Above	See Row 17 Above			0	0	See Row 14 Above	See Row 14 Above	
	Secondary Clarifier Check Valve and Two RAS Motors Installation	0%	TBD	See Row 17 Above	See Row 17 Above	See Row 17 Above			0	0	See Row 14 Above	See Row 14 Above	
	Chlorination/PAA System Mixer Motor Replacement	0%	TBD	See Row 17 Above	See Row 17 Above	See Row 17 Above			0	0	See Row 14 Above	See Row 14 Above	
	Utility Water Pump Replacement	0%	TBD	See Row 17 Above	See Row 17 Above	See Row 17 Above			0	0	See Row 14 Above	See Row 14 Above	
18	Pretreatment Program Update (following NPDES permit issuance) (AM)	0%	TBD	24,500	6/4/2025	6/4/2025			0	24,500	Pretreat: 801-02430 501-02440	Goldie Assoc Sonya Harrison	
19	Seneca Creek FM Replacement Constr Administration/Inspect (#2023-05; CE)	85%	SUB: 10/22/25 FIN: 11/21/25	140,000	RFB #2023-05	4/29/2024	2/3/2025	6/5/2025	75,000	65,000	O&M CIP: Con Sys 1401-06071	GMC Daniel Mosher	
				TOTAL AWARDED	216,403	TOTAL FUNDS OBLIGATED/ACTUAL TO DATE:				110,753	105,650	TOTAL AWARDED	BUDGET REMAINING

FY2026 O&M FUND PROJECTS

CONSENT ORDER ENGINEERING AND OPERATIONS AND MAINTENANCE TASKS

8/18/2025 11:57

Row #	FY 2026 O&M Project (Project # (if applicable); PM) CANNOT CARRY OVER TO NEXT FISCAL YEAR WITHOUT BUDGET APPROVAL	Notes
1	<b>Consent Order 21-025-W Project: Biannual Compliance Report (CE)</b>	<b>DUE TO SCDES EVERY SIX MONTHS.</b> Reports submitted: 11/14/21, 5/9/22, 11/10/22, 5/9/23, 11/9/23, 5/10/24, 11/8/24, 5/9/24. <b>Next report due 11/10/2025.</b>
2	<b>Agency Reconstitution (Sewer Feasibility Implementation) (Board, Others)</b>	See "Agency Reconstitution" sheet to track progress.
3	<b>Completion of Development Guide (AM)</b>	8/5: A McCullough reviewing approx 15 dates. 8/13: Have received 22 draft documents from AM for consideration.
4	<b>Development Policy Revision (CE)</b>	
5	<b>Indefinite Delivery Contract for Engineering Services (CE)</b>	8/13: Sent to K Wunder for legal review.
6	<b>Arc Flash 70E Assessment of WRF, PSs, and Other Facilities (AM)</b>	8/5: L&S setting up date to visit and will then provide pricing. 8/12: Scheduled to be performed in September.
7	<b>CMMS &amp; Financial Software System Upgrade (CE)</b>	8/14: Received 8 submittals. Review to begin soo and interviews to be scheduled for up to 3 offerors during week of 9/8.
8	<b>Comprehensive Sewer Management Plan <i>Project #2026-04 (KL)</i></b>	8/15: Waiting on cost.
9	<b>Evaluate Perkins PS &amp; Coneross PS Pumps to Determine Repair vs. Replace (KL, EP)</b>	Waiting on IDC.
10	<b>Hydraulic Model/Field Data Collection (CE)</b>	8/12: Met with H Ribelin and developed a plan for data collection. She is to send us a prioritized list of locations where there is at least one key piece of data missing. We will use GPS to gather information.
11	<b>Coneross PS Rotating Assembly for Pumps #4 &amp; #5 (EP)</b>	This is to be determined by the evaluation of Perkins PS & Coneross PS pumps to determine repair vs. replacement.
12	<b>Martin PS Motor Base Restraint System (#2 of 3) (EP)</b>	7/14: KL has ordered this so it can be built.
13	<b>Martin PS Aeration Motor Install (crane needed) (EP)</b>	
14	<b>NPDES Permit Renewal, Including PAA Installation and Operation (JM, KL)</b>	7/23: Submitted comments to SCDES for NPDES Permit.
15	<b>CIP PRIORITY 1A: Portable Generator Connection for WRF (includes engineering) (JM, KL)</b>	7/14: BREC, Blanchard, and Instel will need to be involved in switchgear study. KL to contact Amy Howard. 8/18: KL still needs to contact A Howard. He is to reach out to her very soon.
16	<b>Headworks Flow Pulse and Flow Channel Sensor Install (JM)</b>	7/14: KL coordinating with Paul Davis. Items have been purchased. 8/5: Received quotes.
17	<b>Project #2026-02 General Water Reclamation Facility Installation Projects <i>See below (JM, KL)</i></b>	8/4: Waiting on B Kelley (atty) to review prior to advertising. KL will need engineering assistance for logistics to replace gates. 8/7: Sent draft RFB to B Kelley for legal review as required by procurement code. 8/12: Received copy from BK.
	<b>CIP PRIORITY 1A: Primary Clarifier Sludge Pump Replacement and Installation</b>	
	<b>CIP PRIORITY 2: Primary Clarifier #2 Scum Pump Replacement (one in FY26, one in FY27)</b>	
	<b>Aeration 10" Mag Meter Installation</b>	
	<b>CIP PRIORITY 1A: Aeration Gate Replacement</b>	
	<b>CIP PRIORITY 1A: Aeration Motor Repair/Replacement</b>	
	<b>Biological Reactor Basin Oxic Motor Replacement</b>	
	<b>Secondary Clarifier Check Valve and Two RAS Motors Installation</b>	
<b>Chlorination/PAA System Mixer Motor Replacement</b>		
	<b>Utility Water Pump Replacement</b>	
18	<b>Pretreatment Program Update (following NPDES permit issuance) (AM)</b>	Waiting on NPDES Permit issue.
19	<b>Seneca Creek FM Replacement Constr Administration/Inspect (#2023-05; CE)</b>	<b>\$80,000 carryforward from FY2025. Obligated/Spent column includes costs from FY2025. Reimbursable by Fountain Residential Properties LLC per agreement.</b> 8/5 Railroad bore scheduled for Sept.

FY2026 RESTRICTED FUND PROJECTS

PROJECTS MAY CARRY ACROSS BUDGET YEARS

8/18/2025 11:57

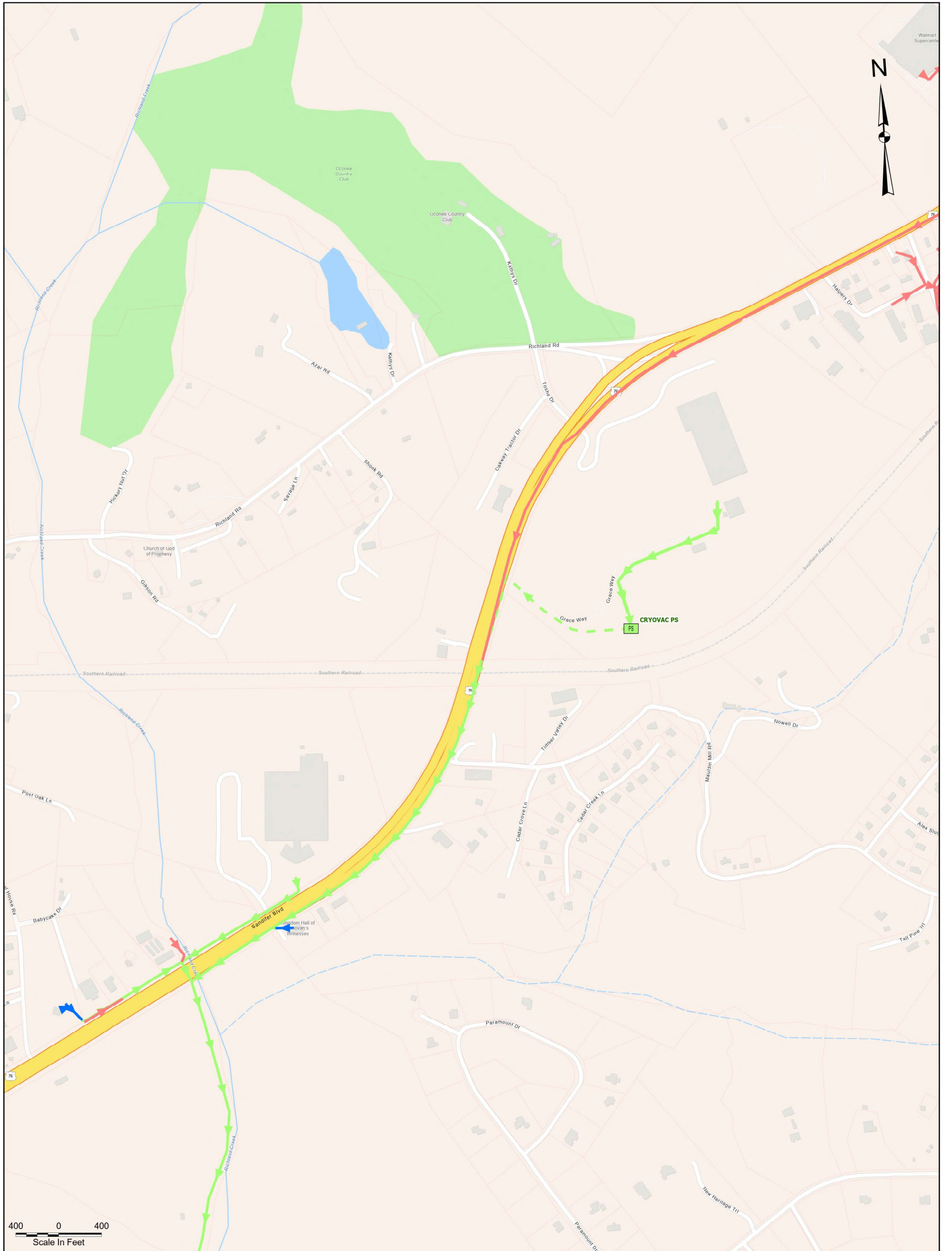
Row #	Restricted Fund Projects (Project Manager)	OJRSA Project #	Approx % Complete	Anticipated Completion	OJRSA Funding Amount (\$)	Max Funding by Others (\$)	PO/Contract Amount (\$)	RESTRICTED FUND PROJECT MILESTONES				Obligated/ Spent Curr + Prev Years (\$)	Budget Remaining (\$)	GL Code (XXXXX = get from Office Mgr)	Comp. Performing (and Project Mgr)
								Bids/RFQ/etc. Issue/Advertised	PO/Contract Signed	Started Work	Completed				
A	I-85 Corridor Phase II See below (CE)	2019-XX and 2023-06	80%	See below	N/A	N/A	N/A	See below	See below	See below		See below	See below	RO&M: CIP 1401-06050	Varies. See Below
	Engineering and Inspection Services COUNTY FUNDED		99%	10/31/2024	0	480,850	480,850	Inherited from Oconee Co	5/4/2023	5/4/2023		431,818	49,032	RO&M: CIP 1401-06050	Davis & Floyd John Reynolds
	Construction EDA/RIA/COUNTY FUNDED		100%	10/31/2024	0	12,311,447	11,687,329	9/27/2022	3/23/2023	6/1/2023	2/4/2025	11,687,329	(0)	RO&M: CIP 1401-06050	Moorhead Construct Kevin Moorhead
	Creek Stabilization & Welcome Center Waterline		5%	TBD	0	78,650	78,650	Contract Amend #3	2/20/2025			0	78,650	RO&M: CIP 1401-06050	Davis & Floyd John Reynolds
B	Exit 4/Oconee Manufacturing Park ("Sewer South Phase III") PS/Sewer ENGINEERING (CE)	CY 2022	99%	11/1/2024	0	0	N/A OCONEE CO PROJ	N/A OCONEE CO PROJ	N/A OCONEE CO PROJ	Sometime in 2022		0	0	TBD	Thomas & Hutton Lee Brackett
C	Dewatering Equipment Replacement at WRF See below (JM, KL)	2024-06	25%	See below	N/A	N/A	N/A	See below	See below	See below		See below	See below	PROJ & CONT 1501-09011	Varies. See Below
	Design, Construction Admin, and Inspection SCIIP MATCH		75%	PHASE II 6/30/2026	440,300	0	440,300	9/15/2023	12/19/2023	1/11/2024		283,100	157,200	PROJ & CONT 1501-09011	KCI Technologies Tom Vollmar
	Construction SCIIP GRANT		5%	PHASE II 6/30/2026	0	4,201,858	4,023,098	3/22/2024	7/30/2024	7/26/2024		0	4,023,098	PROJ & CONT 1501-09011	Harper GC Justin Jones
D	Consent Order Gravity Sewer Rehab Project (SSES/Inspection: 2023) See below (CE, KL)	2024-08	15%	See below	N/A	N/A	N/A	See below	See below	See below		See below	See below	PROJ & CONT 1501-09009	Varies. See Below
	Engineering SCIIP MATCH		75%	9/29/2025	398,000	0	398,000	N/A	9/15/2023	10/3/2023		351,752	46,248	PROJ & CONT 1501-09009	Ardurra Priya Verravalli
	Manhole Resiliency Plan: Project 1c SCIIP MATCH		3%	9/30/2025	87,500	0	87,500	N/A	4/21/2025	4/21/2025		16,200	71,300	PROJ & CONT 1501-09009	Ardurra Priya Verravalli
	Construction/Rehabilitation SCIIP GRANT		25%	SC: 8/25/2025 FC: 9/29/2025	0	4,069,004	4,076,461	8/14/2024	11/20/2024	1/27/2025		152,944	3,923,517	PROJ & CONT 1501-09009	Bio-Nomic Services Buck Stevenson
E	Martin Creek PS Basin Trunk Sewer CCTV Engineer Review and Flow Study Report (CE)	2025-03	100%	3/31/2025	141,000	0	141,000	Consent Order Prof Svcs	9/30/2024			141,000	0	PROJ & CONT 1501-09012	Ardurra Priya Verravalli
F	Gravity Sewer: CONSENT ORDER Evaluation of CCTV/Smoketesting from MH29 to WRF (KL)	2026-05	0%	11/15/2025	31,500	0	31,500	Prof Svcs	8/12/2025			0	31,500	PROJ & CONT 1501-09014	Ardurra Priya Verravalli
G	Consent Order Speeds Creek FM Replacement Engineering Design & Easements Only (CE)	2025-TBD	0%	TBD	TBD	0	TBD	IDC Engineer				0	0	PROJ & CONT 1501-09015	TBD
					1,098,300	8,270,862	9,197,859	TOTAL RESTRICTED FUNDS OBLIGATED/ACTUAL TO DATE:				944,996	8,252,862	TOTAL AWARDED BUDGET REMAINING	

FY2026 RESTRICTED FUND PROJECTS

PROJECTS MAY CARRY ACROSS BUDGET YEARS

8/18/2025 11:57

Row #	Restricted Fund Projects (Project Manager)	Notes
A	I-85 Corridor Phase II See below (CE)	2/10: Roger Sears responded to R Love's email saying water line will need to be handled through encroachment process. 3/5: Signed, submitted Stormwater Notice of Termination 3/24: Signed/sent EDA Federal Financial Report to ACOG. SCDES NPDES Permit Notice of Termination docs sent to Columbia. 7/14: Waiting on record drawings and GIS. 7/21: Spoke with J Reynolds about grass not growing on Phase II project along interstate, he said he'll call contractor because it is a warranty item and we need the grass to stabilize the site. SCDES will hold us accountable for any offsite impact due to erosion. JR sent Moorhead an email same day. 7/25: Received GIS info from R Love. Forwarded to D Gant for review 7/28. <b>Still need to locate/GPS service cleanout at SC59/Fairplay Blvd and shoot elevations of manhole rim/grade elevations.</b> 8/4: Locate clamp received. Waiting for GPR training to be scheduled. <b>8/6: Moorhead acknowledged by email that additional stabilization is required. Likely to be performed in September.</b>
	<b>Engineering and Inspection Services COUNTY FUNDED</b>	
	<b>Construction EDA/RIA/COUNTY FUNDED</b>	
	<b>Creek Stabilization &amp; Welcome Center Waterline</b>	
B	Exit 4/Oconee Manufacturing Park ("Sewer South Phase III") PS/Sewer ENGINEERING (CE)	2/19/2025: G Hart mentioned that he found that A Brock had submitted it and they haven't heard anything from SCDES yet. 3/18: Issued revised Conditional Acceptance letter to A Brock for her to send to T&H if she agreed with conditions.
C	Dewatering Equipment Replacement at WRF See below (JM, KL)	1/6/2025: Received 90% plans, Jackson Electric visited site to assess. 1/22: Received SCDES construction permit application payment request of \$550. 2/4: Board approved contracts. Signed, submitted stormwater permit application. 3/10: Received feedback from SCRIA on contract. KCI will need to oversee a few items and respond. 3/28: Received final contract as approved by RIA for signature. Barbian asked Harper to sign then forward for OJRSA signature. 4/17: Signed contract. 7/25: Looking at November mobilization. Looking at substantial completion in mid-July 2026.
	<b>Design, Construction Admin, and Inspection SCIIP MATCH</b>	
	<b>Construction SCIIP GRANT</b>	
D	<b>Consent Order Gravity Sewer Rehab Project (SSES/Inspection: 2023) See below (CE, KL)</b>	<b>PO/Contract Amount includes \$700,000 owner contingency</b> 7/21: Contractor reports they will have 2 crews (starting today). 7/25: All contractor and subs are onsite and progressing. BNS will be visiting the golf course to review possible additional manholes to rehabilitate. 8/6: Had meeting with Bio-Nomic president, Buck Stevenson, to discuss getting project back on schedule and addressing other issues. 8/8: Received complaint about R/W issue, Bio-Nomic investigated 8/13 and will address. They communicated with property owner. 8/14: Pay App #5 submitted for ACOG review. 8/18: Complaint addressed. Contractor in communication with property owner.
	<b>Engineering SCIIP MATCH</b>	
	<b>Manhole Resiliency Plan: Project 1c SCIIP MATCH</b>	
E	<b>Martin Creek PS Basin Trunk Sewer CCTV Engineer Review and Flow Study Report (CE)</b>	5/5: Received draft report to review. 6/2: Provided comments to Priya. 7/24: Received final report. <b>COMPLETE.</b>
F	<b>Gravity Sewer: CONSENT ORDER Evaluation of CCTV/Smoketesting from MH29 to WRF (KL)</b>	Review CCTV for 9,525 LF of 30" and 36" RCP and 29 manhole inspections to develop list of defects for design of sewer rehab. 8/15: Engineer confirmed receipt of data (delivered a few months ago). They are verifying all information.
G	<b>Consent Order Speeds Creek FM Replacement Engineering Design &amp; Easements Only (CE)</b>	CONSENT ORDER ITEM 7/15/2024: As identified in the 20 Year Master Plan, this force main should be replaced with similar sized pipe. 8/5: Waiting on IDC engineer.



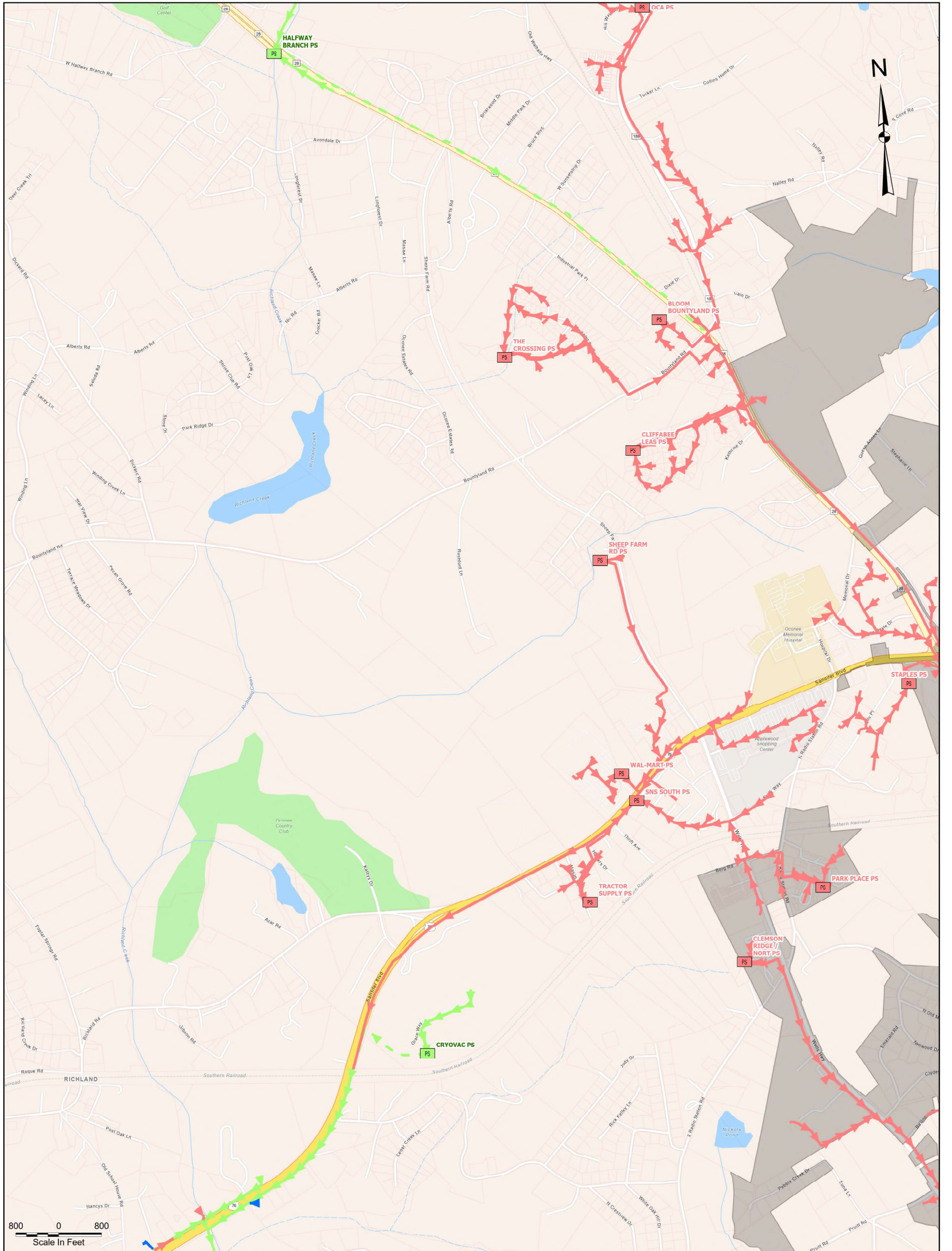

**OJRSA**

Richland Creek Expansion  
Proposal  
Figure 1

TUESDAY, AUGUST 19, 2025

**Legend**

- PS OJRSA
- Gravity Main OJRSA
- Private
- Seneca
- Pressurized Main OJRSA
- Seneca




**OJRSA**

Richland Creek Expansion  
Proposal  
Figure 2

TUESDAY, AUGUST 19, 2025

**Legend**

**Pump Station**

- OJRSA (Green box with PS)
- Seneca (Red box with PS)

**Gravity Main**

- OJRSA (Green line with arrow)
- Private (Blue line with arrow)
- Seneca (Red line with arrow)

**Pressurized Main**

- OJRSA (Green dashed line with arrow)
- Seneca (Red dashed line with arrow)

Municipalities (Grey shaded area)



# Piedmont Municipal Power Agency

BOARD PACK

for

**PMPA Board Meeting**

Thursday, August 21, 2025

10:00 AM (EDT)

Held at:

PMPA Office

121 Village Drive, Greer, SC 29651

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Agenda

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# AGENDA

## PMPA BOARD MEETING



<b>Name:</b>	Piedmont Municipal Power Agency
<b>Date:</b>	Thursday, August 21, 2025
<b>Time:</b>	10:00 AM to 2:00 PM (EDT)
<b>Location:</b>	PMPA Office, 121 Village Drive, Greer, SC 29651 <a href="https://pmpa.zoom.us/j/82154409700?pwd=a5cserX8xE4gySNhb2eIHudg2V3OVX.1">https://pmpa.zoom.us/j/82154409700?pwd=a5cserX8xE4gySNhb2eIHudg2V3OVX.1</a>
<b>Board Members:</b>	Blake Stone, Andy Sevic (Chair), Mayor Brian Ramey, David Vehaun, Eric Goodwin, Mayor Foster Senn, Jason Taylor, Jimmy Bagley, Joe Nichols, John Young, Keith Wood, Kevin Bronson, Lance Davis, Marc Regier, Mike Richard, Steve Bratton, Joey Meadors, Mike Clary, David Dorman, Mayor Randy Randall
<b>Attendees:</b>	Angie Hoover, Brandon Audet, Cindy Frierson, Dedra Howell, Dennis Cameron, Gary Brunault, Joel Ledbetter, JulieAnne London, Kenny Bradley, Lynn Price, Mike Frazier, Rion Foley, Robby Townsend, Tom Gressette, Tracy Quinn, Will Blanton

### 1. Call to Order

#### 1.1 Identify Virtual Attendees

#### 1.2 Declaration of Quorum

#### 1.3 Invocation

### 2. Approval of Minutes

#### 2.1 Confirm Minutes

Supporting Documents:

2.1.a	Minutes : PMPA Board Meeting - 19 Jun 2025	6
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#### 2.2 Vote to Approve Minutes of June 19, 2025 Board Meeting

### 3. Acceptance of Financial Report

#### 3.1 June and July 2025

Supporting Documents:

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## 4. Reports

### 4.1 Finance

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### 4.4 Management

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## 5. Items for Discussion

### 5.1 Energy Emergency Alerts

Supporting Documents:

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## 6. Action Item

### 6.1 Approval of Capital Request for Power Uprate at Catawba Nuclear

**For Decision**

Supporting Documents:

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## 7. Executive Session

### 7.1 Vote to enter into Executive Session

**7.2 Discussion of Matters Pertaining to Contractual Negotiations**

**7.3 Vote to return to Regular Session**

8. Actions to be taken based on discussion in Executive Session

9. Participant Discussion

10. Adjourn

**10.1 Adjourn**

**Next meeting:** PMPA Board Meeting - Sep 18, 2025, 10:00 AM

# MINUTES (in Review)

## PMPA BOARD MEETING



<b>Name:</b>	Piedmont Municipal Power Agency
<b>Date:</b>	Thursday, June 19, 2025
<b>Time:</b>	10:00 AM to 12:00 PM (EDT)
<b>Location:</b>	PMPA Office, 121 Village Drive, Greer, SC 29651
<b>Board Members:</b>	Andy Sevic (Chair), Mike Clary, Mayor Randy Randall, Joey Meadors, Eric Goodwin, David Dorman, Steve Bratton, Mike Richard, Marc Regier, John Young, Keith Wood, Mayor Foster Senn, Jason Taylor, Jimmy Bagley, David Vehaun, Joe Nichols, Lance Davis, Kevin Bronson, Mayor Brian Ramey
<b>Attendees:</b>	Joel Ledbetter, JulieAnne London, Mike Frazier, Dennis Cameron, Tracy Quinn, Lynn Price, Will Blanton, Kenny Bradley, Gary Brunault, Rion Foley
<b>Apologies:</b>	Blake Stone, Angie Hoover, Brandon Audet, Cindy Frierson, Dedra Howell, Robby Townsend
<b>Guests:</b>	Belton Ziegler, Mark White, Andrea Kelley, and Max White
<b>Notes:</b>	Virtual Attendees: Kevin Bronson, Gary Brunault, and Andrea Kelley

### 1. Call to Order

#### 1.1 Identify Virtual Attendees

#### 1.2 Declaration of Quorum

Chairman Sevic declared that a quorum is present and the Board can conduct business.

#### 1.3 Invocation

Mr. Ledbetter gave the invocation.

### 2. Administration of Oath of Office to new Board Member

#### 2.1 Oath of Office - Mike Clary, City of Abbeville

Mrs. Quinn, Office Manager/Executive Secretary, who is also a Notary Public, administered the oath of office to Mike Clary, who has been appointed Alternate Director from Abbeville (copy attached).

### 3. Approval of Minutes

#### 3.1 Confirm Minutes

**PMPA Board Meeting May 22, 2025**, the minutes were confirmed as presented.

### 3.2 Vote to Approve Minutes of May 22, 2025 Board Meeting



#### Vote to Approve Minutes of May 22, 2025 Board Meeting

10 Supported  
0 Opposed  
0 Abstained

**Decision Date:** Jun 19, 2025  
**Mover:** David Dorman  
**Seconder:** Mayor Foster Senn  
**Outcome:** Approved

## 4. Acceptance of Financial Report

### 4.1 May 2025



#### May 2025

10 Supported  
0 Opposed  
0 Abstained

**Decision Date:** Jun 19, 2025  
**Mover:** Mayor Randy Randall  
**Seconder:** Keith Wood  
**Outcome:** Approved

## 5. Reports

### 5.1 Finance

Ms. London addressed a question that was posed at the May 2025 meeting as to what impact this year's increase in working capital will have on the proposed rate increased in 2026. Ms. London explained that part of this year's increase in working capital is due to the delay in expenditures for the Laurens Transmission line. In addition, all future rate increases were designed to meet the minimum working capital target in 2028 as set by the Working Capital Policy, and even with this year's working capital increase PMPA is still projected to be at the minimum working capital target in 2028. This subject will be discussed more thoroughly at the October planning session.

### 5.2 Engineering

Mr. Frazier reviewed the standard engineering reports for May that were included in the Board Pack.

Mr. Frazier also reviewed the current status of the Laurens Transmission Line.

### 5.3 Catawba

Mr. Cameron reviewed the Catawba and McGuire report included in the Board Pack and any updates since that report.

## 5.4 Management

Mr. Ledbetter discussed the Public Power Reception next week in Washington and stated that representatives from SCAMPS, Santee Cooper, Electricities, and PMPA would be attending.

Mr. Ledbetter also requested the Participants consider providing door prizes for the Power Conference as they have in the past.

Mr. Ledbetter discussed potential topics for the Participant roundtable planned for the Power Conference and stated he would email the Board the topics and potential presenters.

## 6. Items for Discussion

### 6.1 Participant's declaration of excess Catawba



#### Mr. Ledbetter discussed the resolutions received from Greer and R...

Mr. Ledbetter discussed the resolutions received from Greer and Rock Hill declaring all of their Catawba allocation as excess beginning January 1, 2029. Section 11 of the Catawba Project Power Sales Agreement and the Board policy adopted April 2024 address the procedure for the sale of Catawba excess. The Board policy gives Participants that may be interested in the excess 90 days to negotiate a purchase. Six Participants are selling excess capacity from their allocation and can be presumed to not want to purchase excess, and the remaining 2 Participants declared they are not interested in additional Catawba capacity. Mr. Ledbetter stated that it was appropriate to waive the 90 day negotiation period as stated in the Policy.

The resolution from the City of Rock Hill requests "... PMPA to market 100% of the City's share of its Catawba Project Output along with the excess declared by other participants." Mr. Ledbetter stated that the 47.5 MW excess of other Participants had already been marketed and a proposal received, and requested clarification from Rock Hill that they understood a sale of its Catawba excess would be a separate marketing and sale. Rock Hill affirmed and agreed that its sale would be a separate sale.

A motion was made by Mr. Dorman, with a second by Mr. Young to waive the 90-day notice which effectively waives any Participants right to purchase the excess.

Approved unanimously.

10 Supported

0 Opposed

0 Abstained

<b>Decision Date:</b>	Jun 19, 2025
<b>Mover:</b>	David Dorman
<b>Seconder:</b>	John Young
<b>Outcome:</b>	Approved

## 7. Action Item

### 7.1 Resolution 25-01: Approval of Catawba Project Power Sales Renewal Agreement



#### Resolution 25-01: Approval of Catawba Project Power Sales Renewal Agreement

Mayor Senn made a motion, with a second by Mayor Randall, to adopt Resolution 25-01. Any changes to the Catawba Project Power Sales Renewal

Agreement must be agreed to by both the General Manager and the Chairman. The approved Resolution is attached to these minutes.

7 Supported

0 Opposed

3 Abstentions (Greer, Rock Hill, and Union)

**Decision Date:** Jun 19, 2025

**Mover:** Mayor Foster Senn

**Second:** Mayor Randy Randall

**Outcome:** Approved

## 8. Executive Session

### 8.1 Vote to enter into Executive Session



#### Vote to enter into Executive Session

10 Supported

0 Opposed

0 Abstained

**Decision Date:** Jun 19, 2025

**Mover:** John Young

**Second:** David Dorman

**Outcome:** Approved

### 8.2 Discussion of Personnel Matters

### 8.3 Vote to return to Regular Session



#### Vote to return to Regular Session

10 Supported

0 Opposed

0 Abstained

**Decision Date:** Jun 19, 2025

**Mover:** Joe Nichols

**Second:** Jimmy Bagley

**Outcome:** Approved

## 9. Participant Discussion

## 10. Miscellaneous

### 10.1 Annual Engineering Report

The Annual Engineering Report for 2024 was included in the Board Pack as information. A copy will be emailed to all Board members and alternates.

## 11. Adjourn

### 11.1 Adjourn

**Next meeting:** PMPA Board Meeting - Aug 21, 2025, 10:00 AM

A motion was made by Mr. Dorman, with a second by Mr. Young, to adjourn the meeting.

Motion passed.

**Signature:** \_\_\_\_\_

**Date:** \_\_\_\_\_

**PIEDMONT MUNICIPAL POWER AGENCY**  
**COMPARATIVE STATEMENT OF NET POSITION**  
**AS OF JUNE 30, 2025**  
**(DOLLARS IN THOUSANDS)**

	<u>LAST MONTH</u>	<u>INCREASE</u>	<u>DECREASE</u>	<u>THIS MONTH</u>
<b>ASSETS</b>				
<b>CURRENT UNRESTRICTED ASSETS:</b>				
Cash And Markable Debt Securities (W/C)	\$74,245	\$2,239	\$0	\$76,484
Revenue Fund Valuation	(2)	0	0	(2)
Fuel	(2,840)	914	0	(1,925)
Participants Accounts Receivable (W/C)	17,326	2,557	0	19,883
Other Accounts Receivable (W/C)	697	0	149	547
Materials & Supplies	20,070	278	0	20,348
<b>TOTAL CURRENT UNRESTRICTED ASSETS</b>	<b>109,495</b>	<b>5,839</b>	<b>0</b>	<b>115,334</b>
<b>CURRENT RESTRICTED ASSETS:</b>				
Debt Service	36,179	7,195	0	43,375
Debt Service Reserve	46,187	0	0	46,187
Reserve and Contingency	3,527	1,404	0	4,931
Decommissioning	142,518	536	0	143,055
Supplemental Power Reserve	1,600	0	0	1,600
Restricted Funds Valuation	(597)	1,121	0	524
<b>TOTAL CURRENT RESTRICTED ASSETS</b>	<b>229,414</b>	<b>10,257</b>	<b>0</b>	<b>239,672</b>
<b>TOTAL CURRENT ASSETS</b>	<b>338,909</b>	<b>16,096</b>	<b>0</b>	<b>355,005</b>
<b>CAPITAL ASSETS, NET:</b>				
Generation	357,672	0	744	356,928
Transmission	4,053	0	11	4,042
LDMS/SCADA	439	0	12	426
General	495	0	9	486
Nuclear Fuel - In Stock And Progress	26,864	258	0	27,121
Nuclear Fuel - In Reactor	20,188	0	1,172	19,016
Construction In Progress	23,347	558	0	23,904
<b>TOTAL CAPITAL ASSETS, NET</b>	<b>433,057</b>	<b>0</b>	<b>1,133</b>	<b>431,924</b>
<b>OTHER NON CURRENT ASSETS:</b>				
Net Costs Recoverable From Future Participants Billings	211,161	0	4,093	207,069
Participant Settlement Receivable	45,400	0	0	45,400
<b>TOTAL NON CURRENT ASSETS</b>	<b>689,618</b>	<b>0</b>	<b>5,226</b>	<b>684,392</b>
<b>TOTAL ASSETS</b>	<b>\$1,028,528</b>	<b>\$10,870</b>	<b>\$0</b>	<b>\$1,039,398</b>
<b>DEFERRED OUTFLOWS:</b>				
Asset Retirement Obligation	\$36,499	\$0	\$79	\$36,420
Redemption Losses, Net	3,955	0	54	3,900
Losses On Advanced Refunding Of Debt, Net	4,301	0	81	4,219
<b>TOTAL DEFERRED OUTFLOWS</b>	<b>\$44,754</b>	<b>\$0</b>	<b>\$214</b>	<b>\$44,540</b>

**PIEDMONT MUNICIPAL POWER AGENCY**  
**COMPARATIVE STATEMENT OF NET POSITION**  
**AS OF JUNE 30, 2025**  
**(DOLLARS IN THOUSANDS)**

	<u>LAST MONTH</u>	<u>INCREASE</u>	<u>DECREASE</u>	<u>THIS MONTH</u>
<b>LIABILITIES</b>				
<b>CURRENT LIABILITIES:</b>				
Accounts Payable - General (WC)	\$122	\$0	\$122	\$0
Accounts Payable - Duke (WC)	724	484	0	1,208
Accounts Payable - Other (WC)	802	2,276	0	3,077
Accrued Expenses - Payroll (W/C)	0	0	0	0
Accrued Expenses - Vacation (W/C)	88	0	0	88
Accrued Expenses - Sick (W/C)	178	0	0	178
Accrued Expenses - Property Taxes (W/C)	4,220	843	0	5,063
<b>TOTAL CURRENT LIABILITIES</b>	<b>6,134</b>	<b>3,481</b>	<b>0</b>	<b>9,615</b>
<b>CURRENT LIABILITIES PAYABLE FROM RESTRICTED ASSETS:</b>				
Accrued Interest Payable	188,859	2,776	0	191,634
<b>TOTAL CURRENT LIABILITIES</b>	<b>194,993</b>	<b>6,256</b>	<b>0</b>	<b>201,249</b>
<b>LONG-TERM LIABILITIES:</b>				
Bonds - Including Current Installment	340,015	0	0	340,015
Bonds - Settlement	48,330	0	0	48,330
Bond Discounts	(29)	0	0	(28)
Bond Premium	34,349	0	553	33,797
CAB	80,330	0	0	80,330
Asset Retirement Obligation	185,141	495	0	185,636
Participant Interest Payable (W/C)	144	5	0	149
Other Postemployment Benefits	1,724	0	0	1,724
<b>TOTAL LONG-TERM LIABILITIES</b>	<b>690,005</b>	<b>0</b>	<b>52</b>	<b>689,952</b>
<b>TOTAL LIABILITIES</b>	<b>\$884,997</b>	<b>\$6,204</b>	<b>\$0</b>	<b>\$891,201</b>
<b>DEFERRED INFLOWS:</b>				
Postemployment Benefits	\$216	\$0	\$0	\$216
<b>NET POSITION</b>				
Net Investments In Capital Assets	(\$13,353)	\$0	\$716	(\$14,069)
Restricted For Other	1,600	0	0	1,600
Unrestricted	199,822	5,168	0	204,990
<b>TOTAL NET POSITION</b>	<b>\$188,069</b>	<b>\$4,452</b>	<b>\$0</b>	<b>\$192,521</b>
<b>INFORMATIONAL PURPOSES:</b>				
Working Capital	\$85,989	\$1,161	\$0	\$87,150

**PIEDMONT MUNICIPAL POWER AGENCY**  
**FINANCIAL SUMMARY**  
**AS OF JUNE 30, 2025**

**MAJOR DEVIATIONS FROM THE BUDGET WERE:**

(In Millions)	JUNE VARIANCES		
	\$	%	Comments
Working Capital	\$0.70	150.2%	
Participant Power Sales	\$0.89	4.5%	
Surplus Sales	\$0.12	34.0%	Santee adjustments related to April and May sales
Miscellaneous Income/Expense	\$0.05	6.8%	Lower than budgeted Duke fees
Interest Income	(\$0.07)	-7.4%	Lower than budgeted yields on DCom and R&C funds, partially offset by higher than budgeted yields on Revenue fund
Catawba Project Costs	\$0.50	7.7%	Lower than budgeted electrical operations and miscellaneous maintenance costs
Supplemental Power Costs	(\$0.84)	-16.7%	Higher than budgeted Santee capacity (\$0.2) and energy (\$0.2), higher than budgeted transmission costs due to increased revenue requirements that took effect in June (\$0.2), and Duke SEEM adjustments (\$0.2)
Catawba Capital Additions	\$0.78	59.2%	Lower than budgeted expenses due to timing of expenses
PMPA Capital Additions	\$0.19	89.6%	Primarily timing of Laurens Transmission line project
Other	(\$0.91)	-13.2%	Primarily higher R&C transfer due to timing of Cap Adds

(In Millions)	YEAR-TO-DATE VARIANCES		
	\$	%	Comments
Working Capital	\$5.94	1004.6%	
Participant Power Sales	\$1.45	1.3%	
Surplus Sales	\$1.40	37.9%	Higher energy sales and pricing received for sales than budgeted
Miscellaneous Income/Expense	\$0.31	7.6%	Lower than budgeted Duke fees
Interest Income	(\$0.23)	-4.7%	
Catawba Project Costs	\$2.88	7.0%	Lower than budgeted O&M costs & year-end Duke benefits, insurance, and G&A true-up
Supplemental Power Costs	(\$1.39)	-6.3%	Higher purchases in January due to colder temperatures and increased capacity and transmission costs in June.
Catawba Capital Additions	\$0.02	0.2%	
PMPA Capital Additions	\$1.12	67.7%	Primarily timing of Laurens Transmission line project
Other	\$0.37	0.9%	

Favorable >5%
Near Budget +/- 5%
Unfavorable < 5%

**PIEDMONT MUNICIPAL POWER AGENCY**  
**STATEMENT OF REVENUE & EXPENSE PER THE BOND RESOLUTION**  
**AS OF JUNE 30, 2025**  
**(DOLLARS IN THOUSANDS)**

	CURRENT MONTH			YEAR TO DATE			
	ACTUAL	BUDGET	OVER(UNDER)	ACTUAL	BUDGET	OVER(UNDER)	%
<b>CATAWBA PROJECT:</b>							
CATAWBA POWER SALES							
Participant	\$14,877	\$14,632	\$245	\$87,638	\$86,513	\$1,125	1.3%
Duke-Exchange Energy	1,015	948	67	5,801	5,823	(22)	(0.4%)
Other-Surplus	457	341	116	5,079	3,683	1,396	37.9%
TOTAL	16,349	15,921	428	98,518	96,019	2,499	2.6%
CATAWBA POWER COSTS							
Operations & Maintenance	1,637	2,081	(444)	13,132	15,062	(1,930)	(12.8%)
Fuel Amort(Fuel Acct Deposit)	1,172	1,191	(19)	7,009	7,187	(178)	(2.5%)
Purch Power-Duke-McGuire Cap	20	20	0	121	122	(1)	(0.6%)
-McGuire Energy	1,048	1,016	32	5,636	5,740	(104)	(1.8%)
Customer Acct and G&A-Duke	790	758	32	4,323	4,550	(227)	(5.0%)
Customer Acct and G&A-Agency	348	432	(84)	2,219	2,616	(397)	(15.2%)
Property Tax Equivalent	834	834	0	5,011	5,009	2	0.0%
Tax Other-Duke	93	106	(13)	584	633	(49)	(7.8%)
TOTAL	5,942	6,438	(496)	38,035	40,919	(2,884)	(7.0%)
FUNDS AVAILABLE FROM OPERATIONS	10,406	9,483	923	60,483	55,100	5,383	9.8%
INTEREST INCOME	825	891	(66)	4,550	4,776	(226)	(4.7%)
MISCELLANEOUS INCOME(EXPENSE)	(630)	(676)	46	(3,752)	(4,059)	307	(7.6%)
FUNDS AVAILABLE FOR CAPITAL NEEDS	10,601	9,698	903	61,281	55,817	5,464	9.8%
OTHER AVAILABLE FUNDS							
Debt Service-Principal	0	0	0	66,565	66,565	0	0.0%
-Interest	0	0	0	10,952	10,946	6	0.1%
Reserve & Contingency - Capital Additions	536	1,315	(779)	11,329	11,351	(22)	(0.2%)
Fuel	258	53	205	4,927	8,789	(3,862)	(43.9%)
DEPOSITS							
Debt Service-Principal	2,255	2,256	(1)	13,532	13,532	0	0.0%
-Interest	4,431	4,431	0	28,122	28,122	0	0.0%
Reserve & Contingency	1,940	1,940	0	11,640	11,640	0	0.0%
Decommissioning	536	567	(31)	3,244	3,346	(102)	(3.0%)
Inventory	278	40	238	(404)	(31)	(373)	1,204.0%
PAYMENTS							
Debt Service-Principal	0	0	0	66,565	66,565	0	0.0%
-Interest	0	0	0	10,952	10,946	6	0.1%
Capital Additions	536	1,315	(779)	11,329	11,351	(22)	(0.2%)
Fuel	258	53	205	4,927	8,789	(3,862)	(43.9%)
TRANSFERS (TO) FROM							
Reserve & Contingency	0	0	0	0	0	0	0.0%
DSR Release/Special Transfers	0	0	0	0	0	0	0.0%
Catawba Working Capital	1,161	464	697	5,145	(792)	5,937	(749.6%)
Supplemental Working Capital	0	0	0	0	0	0	0.0%
WORKING CAP INCREASE(DECREASE)	\$1,161	\$464	\$697	\$5,145	(\$792)	\$5,937	(749.6%)

**PIEDMONT MUNICIPAL POWER AGENCY**  
**STATEMENT OF REVENUE & EXPENSE PER THE BOND RESOLUTION**  
**AS OF JUNE 30, 2025**  
**(DOLLARS IN THOUSANDS)**

	CURRENT MONTH			YEAR TO DATE			
	ACTUAL	BUDGET	OVER(UNDER)	ACTUAL	BUDGET	OVER(UNDER)	%
<b>SUPPLEMENTAL:</b>							
SUPPLEMENTAL POWER SALES							
Participants-Supplemental Power	5,778	5,138	640	23,286	22,961	325	1.4%
-Leased Facilities	26	29	(3)	158	169	(11)	(6.4%)
-Other	121	106	15	621	671	(50)	(7.5%)
TOTAL	<u>5,925</u>	<u>5,273</u>	<u>652</u>	<u>24,065</u>	<u>23,801</u>	<u>264</u>	<u>1.1%</u>
SUPPLEMENTAL POWER COSTS							
Purch Power-Supp Capacity	1,061	878	183	5,302	5,268	34	0.7%
-Supp Energy	2,210	1,863	347	4,080	3,352	728	21.7%
Purch Power-Participants	1,124	1,108	16	6,265	6,436	(171)	(2.7%)
Purch Power-Other	269	239	30	1,572	1,239	333	26.8%
Transmission	1,101	802	299	5,324	4,724	600	12.7%
Transmission-Agency	0	5	(5)	24	25	(1)	(4.4%)
Leased Facilities-Duke	37	38	(1)	217	226	(9)	(4.0%)
Meter-Agency	0	1	(1)	94	106	(12)	(11.3%)
Customer Acct and G&A-Duke	0	0	0	0	0	0	0.0%
Customer Acct and G&A-Agency	92	116	(24)	590	703	(113)	(16.1%)
Property Tax Equivalent	9	9	0	52	54	(2)	(3.6%)
TOTAL	<u>5,902</u>	<u>5,059</u>	<u>843</u>	<u>23,519</u>	<u>22,133</u>	<u>1,386</u>	<u>6.3%</u>
FUNDS AVAILABLE FROM OPERATIONS	23	214	(191)	546	1,668	(1,122)	(67.3%)
MISCELLANEOUS INCOME(EXPENSE)	201	199	2	1,200	1,199	1	0.1%
FUNDS AVAILABLE FOR CAPITAL NEEDS	<u>224</u>	<u>413</u>	<u>(189)</u>	<u>1,746</u>	<u>2,867</u>	<u>(1,121)</u>	<u>(39.1%)</u>
PAYMENTS							
Debt Service-Interest	202	201	1	1,211	1,211	0	0.0%
Capital Additions-Transmission	3	211	(208)	190	1,263	(1,073)	(85.0%)
-LDMS/SCADA	0	0	0	326	341	(15)	(4.4%)
-General	19	1	18	19	52	(33)	(63.7%)
WORKING CAP INCREASE(DECREASE)	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>0.0%</u>

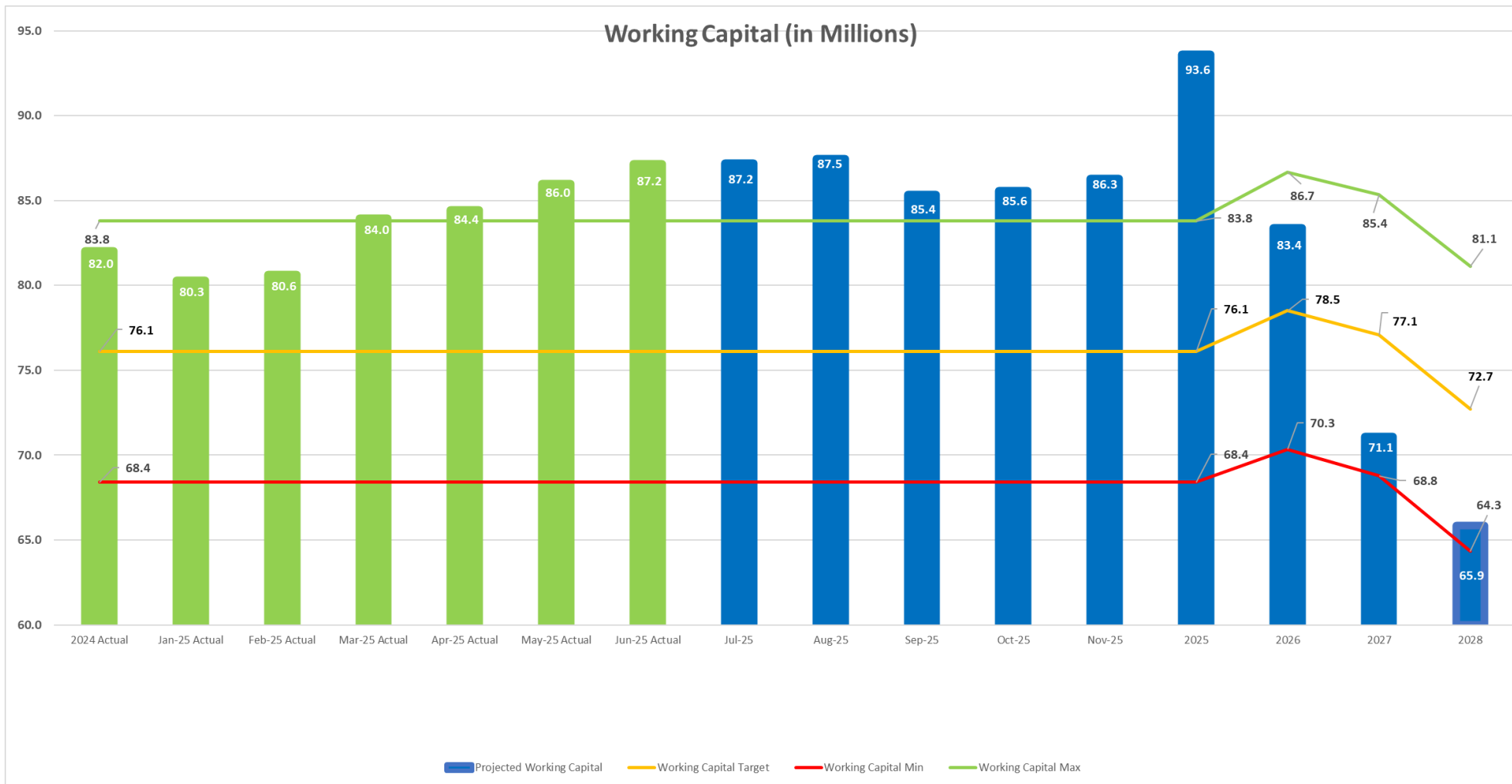
## PIEDMONT MUNICIPAL POWER AGENCY STATEMENT OF G&A EXPENSE AS OF JUNE 30, 2025

CURRENT MONTH				YEAR TO DATE				
ACTUAL	BUDGET	OVER(UNDER)	%	ACTUAL	BUDGET	OVER(UNDER)	%	% ANNUAL BUDGET
				<b><u>G&amp;A-OFFICE EXPENSE</u></b>				
\$131,743	\$138,200	(\$6,457)	(4.7)	\$796,245	\$844,600	(\$48,355)	(5.7)	44.3
9,253	9,500	(247)	(2.6)	63,852	68,900	(5,048)	(7.3)	55.5
19,465	19,100	365	1.9	117,178	115,000	2,178	1.9	50.9
12,770	12,700	70	0.6	82,867	82,500	367	0.4	50.2
178	300	(122)	(40.7)	925	700	225	32.1	46.3
5,057	400	4,657	1,164.3	300,413	309,100	(8,687)	(2.8)	79.3
1,549	2,100	(551)	(26.2)	10,420	12,600	(2,180)	(17.3)	41.7
1,457	1,600	(143)	(8.9)	8,129	8,600	(471)	(5.5)	47.8
512	2,100	(1,588)	(75.6)	2,701	12,600	(9,899)	(78.6)	10.8
0	100	(100)	(100.0)	559	900	(341)	(37.9)	28.0
244	100	144	144.0	293	600	(307)	(51.2)	14.7
902	1,300	(398)	(30.6)	9,231	11,700	(2,469)	(21.1)	16.2
0	200	(200)	(100.0)	2,397	1,500	897	59.8	79.9
298	500	(202)	(40.4)	3,623	3,500	123	3.5	51.8
11,744	2,700	9,044	335.0	23,082	80,100	(57,018)	(71.2)	22.6
39,082	79,200	(40,118)	(50.7)	103,280	198,300	(95,020)	(47.9)	34.4
2,189	1,000	1,189	118.9	5,882	23,400	(17,518)	(74.9)	19.6
1,737	2,900	(1,163)	(40.1)	11,698	18,000	(6,302)	(35.0)	32.5
(394)	0	(394)	0.0	4,604	5,000	(396)	(7.9)	92.1
0	0	0	0.0	11,361	13,000	(1,639)	(12.6)	87.4
85,463	100,000	(14,537)	(14.5)	95,589	111,000	(15,411)	(13.9)	86.1
252	100	152	152.0	28,598	29,600	(1,002)	(3.4)	26.0
0	3,000	(3,000)	(100.0)	0	3,000	(3,000)	(100.0)	0.0
1,918	40,200	(38,282)	(95.2)	119,840	241,800	(121,960)	(50.4)	23.8
9,845	9,400	445	4.7	55,792	56,400	(608)	(1.1)	49.4
0	500	(500)	(100.0)	0	3,000	(3,000)	(100.0)	0.0
8,539	13,500	(4,961)	(36.7)	295,642	286,100	9,542	3.3	73.4
<b>343,803</b>	<b>440,700</b>	<b>(96,897)</b>	<b>(22.0)</b>	<b>2,154,201</b>	<b>2,541,500</b>	<b>(387,299)</b>	<b>(15.2)</b>	<b>47.2</b>
				<b><u>G&amp;A-OUTSIDE SERVICES</u></b>				
57,924	76,200	(18,276)	(24.0)	386,249	457,500	(71,251)	(15.6)	42.2
34,265	27,500	6,765	24.6	127,183	165,000	(37,817)	(22.9)	38.5
0	0	0	0.0	70,740	70,000	740	1.1	101.1
0	1,100	(1,100)	(100.0)	60,778	65,300	(4,522)	(6.9)	24.5
3,995	0	3,995	0.0	8,120	5,000	3,120	62.4	162.4
0	2,400	(2,400)	(100.0)	1,050	14,400	(13,350)	(92.7)	3.6
<b>96,184</b>	<b>107,200</b>	<b>(11,016)</b>	<b>(10.3)</b>	<b>654,120</b>	<b>777,200</b>	<b>(123,080)</b>	<b>(15.8)</b>	<b>41.0</b>
<b>\$439,987</b>	<b>\$547,900</b>	<b>(\$107,913)</b>	<b>(19.7)</b>	<b>\$2,808,321</b>	<b>\$3,318,700</b>	<b>(\$510,379)</b>	<b>(15.4)</b>	<b>45.6</b>
				<b><u>TRANSMISSION EXPENSE-AGENCY</u></b>				
\$0	\$5,000	(\$5,000)	(100.0)	\$23,908	\$25,000	(\$1,092)	(4.4)	47.8
0	1,000	(1,000)	(100.0)	94,021	106,000	(11,979)	(11.3)	69.1
<b>\$0</b>	<b>\$6,000</b>	<b>(\$6,000)</b>	<b>(100.0)</b>	<b>\$117,929</b>	<b>\$131,000</b>	<b>(\$13,071)</b>	<b>(10.0)</b>	<b>63.4</b>
				<b>TOTAL XMSN EXPENSE</b>				

# PIEDMONT MUNICIPAL POWER AGENCY

## AS OF JUNE 30, 2025

**After this month's operations, PMPA had \$87.2 million in working capital, which was \$5.9 million better than the YTD budget.**



**PIEDMONT MUNICIPAL POWER AGENCY**  
**COMPARATIVE STATEMENT OF NET POSITION**  
**AS OF JULY 31, 2025**  
**(DOLLARS IN THOUSANDS)**

	<u>LAST MONTH</u>	<u>INCREASE</u>	<u>DECREASE</u>	<u>THIS MONTH</u>
<b>ASSETS</b>				
<b>CURRENT UNRESTRICTED ASSETS:</b>				
Cash And Markable Debt Securities (W/C)	\$76,484	\$1,938	\$0	\$78,422
Revenue Fund Valuation	(2)	0	0	(2)
Fuel	(1,925)	953	0	(973)
Participants Accounts Receivable (W/C)	19,883	1,413	0	21,296
Other Accounts Receivable (W/C)	547	0	506	42
Materials & Supplies	20,348	156	0	20,504
<b>TOTAL CURRENT UNRESTRICTED ASSETS</b>	<b>115,334</b>	<b>3,955</b>	<b>0</b>	<b>119,289</b>
<b>CURRENT RESTRICTED ASSETS:</b>				
Debt Service	43,375	0	2,106	41,269
Debt Service Reserve	46,187	0	0	46,187
Reserve and Contingency	4,931	896	0	5,827
Decommissioning	143,055	590	0	143,645
Supplemental Power Reserve	1,600	0	0	1,600
Restricted Funds Valuation	524	0	0	524
<b>TOTAL CURRENT RESTRICTED ASSETS</b>	<b>239,672</b>	<b>0</b>	<b>619</b>	<b>239,052</b>
<b>TOTAL CURRENT ASSETS</b>	<b>355,005</b>	<b>3,335</b>	<b>0</b>	<b>358,341</b>
<b>CAPITAL ASSETS, NET:</b>				
Generation	356,928	0	744	356,184
Transmission	4,042	0	11	4,030
LDMS/SCADA	426	0	12	414
General	486	0	9	477
Nuclear Fuel - In Stock And Progress	27,121	259	0	27,380
Nuclear Fuel - In Reactor	19,016	0	1,211	17,804
Construction In Progress	23,904	1,044	0	24,948
<b>TOTAL CAPITAL ASSETS, NET</b>	<b>431,924</b>	<b>0</b>	<b>685</b>	<b>431,239</b>
<b>OTHER NON CURRENT ASSETS:</b>				
Net Costs Recoverable From Future Participants Billings	207,069	0	4,058	203,011
Participant Settlement Receivable	45,400	0	0	45,400
<b>TOTAL NON CURRENT ASSETS</b>	<b>684,392</b>	<b>0</b>	<b>4,743</b>	<b>679,650</b>
<b>TOTAL ASSETS</b>	<b>\$1,039,398</b>	<b>\$0</b>	<b>\$1,407</b>	<b>\$1,037,990</b>
<b>DEFERRED OUTFLOWS:</b>				
Asset Retirement Obligation	\$36,420	\$0	\$79	\$36,342
Redemption Losses, Net	3,900	0	54	3,846
Losses On Advanced Refunding Of Debt, Net	4,219	0	81	4,138
<b>TOTAL DEFERRED OUTFLOWS</b>	<b>\$44,540</b>	<b>\$0</b>	<b>\$214</b>	<b>\$44,326</b>

**PIEDMONT MUNICIPAL POWER AGENCY**  
**COMPARATIVE STATEMENT OF NET POSITION**  
**AS OF JULY 31, 2025**  
**(DOLLARS IN THOUSANDS)**

	<u>LAST MONTH</u>	<u>INCREASE</u>	<u>DECREASE</u>	<u>THIS MONTH</u>
<b>LIABILITIES</b>				
<b>CURRENT LIABILITIES:</b>				
Accounts Payable - General (WC)	\$0	\$0	\$0	\$0
Accounts Payable - Duke (WC)	1,208	0	85	1,123
Accounts Payable - Other (WC)	3,077	1,601	0	4,679
Accrued Expenses - Payroll (W/C)	0	0	0	0
Accrued Expenses - Vacation (W/C)	88	0	0	88
Accrued Expenses - Sick (W/C)	178	0	0	178
Accrued Expenses - Property Taxes (W/C)	5,063	844	0	5,907
<b>TOTAL CURRENT LIABILITIES</b>	<b>9,615</b>	<b>2,360</b>	<b>0</b>	<b>11,975</b>
<b>CURRENT LIABILITIES PAYABLE FROM RESTRICTED ASSETS:</b>				
Accrued Interest Payable	191,634	0	6,491	185,144
<b>TOTAL CURRENT LIABILITIES</b>	<b>201,249</b>	<b>0</b>	<b>4,130</b>	<b>197,119</b>
<b>LONG-TERM LIABILITIES:</b>				
Bonds - Including Current Installment	340,015	0	0	340,015
Bonds - Settlement	48,330	0	0	48,330
Bond Discounts	(28)	0	0	(28)
Bond Premium	33,797	0	553	33,244
CAB	80,330	0	0	80,330
Asset Retirement Obligation	185,636	495	0	186,130
Participant Interest Payable (W/C)	149	7	0	156
Other Postemployment Benefits	1,724	0	0	1,724
<b>TOTAL LONG-TERM LIABILITIES</b>	<b>689,952</b>	<b>0</b>	<b>51</b>	<b>689,901</b>
<b>TOTAL LIABILITIES</b>	<b>\$891,201</b>	<b>\$0</b>	<b>\$4,181</b>	<b>\$887,020</b>
<b>DEFERRED INFLOWS:</b>				
Postemployment Benefits	\$216	\$0	\$0	\$216
<b>NET POSITION</b>				
Net Investments In Capital Assets	(\$14,069)	\$0	\$268	(\$14,337)
Restricted For Other	1,600	0	0	1,600
Unrestricted	204,990	2,828	0	207,818
<b>TOTAL NET POSITION</b>	<b>\$192,521</b>	<b>\$2,560</b>	<b>\$0</b>	<b>\$195,080</b>
<b>INFORMATIONAL PURPOSES:</b>				
Working Capital	\$87,150	\$479	\$0	\$87,629

**PIEDMONT MUNICIPAL POWER AGENCY**  
**FINANCIAL SUMMARY**  
**AS OF JULY 31, 2025**

**MAJOR DEVIATIONS FROM THE BUDGET WERE:**

(In Millions)	JULY VARIANCES		
	\$	%	Comments
Working Capital	\$0.45	1451.6%	
Participant Power Sales	\$1.21	5.8%	Primarily driven by higher than normal temperatures this month
Surplus Sales	(\$0.05)	-31.0%	Lower quantity sold than budgeted, driven by higher than normal temperatures this month
Miscellaneous Income/Expense	\$0.13	19.1%	Lower than budgeted Duke fees
Interest Income	\$0.06	7.1%	Primarily higher than budgeted yields in the Revenue fund
Catawba Project Costs	\$0.39	5.9%	Lower than budgeted electrical operations and miscellaneous maintenance costs
Supplemental Power Costs	(\$1.46)	-24.4%	Higher than budgeted Santee capacity (\$0.1) and energy (\$1.1), higher than budgeted transmission costs due to increased revenue requirements that took effect in June (\$0.2), and Duke SEEM adjustments (\$0.1)
Catawba Capital Additions	\$0.27	20.5%	Lower than budgeted expenses due to timing of expenses
PMPA Capital Additions	\$0.21	100.0%	Primarily timing of Laurens Transmission line project
Other	(\$0.32)	-4.5%	

(In Millions)	YEAR-TO-DATE VARIANCES		
	\$	%	Comments
Working Capital	\$6.39	839.0%	
Participant Power Sales	\$2.66	2.0%	
Surplus Sales	\$1.35	35.1%	Higher energy sales and pricing received for sales than budgeted
Miscellaneous Income/Expense	\$0.44	9.2%	Lower than budgeted Duke fees
Interest Income	(\$0.17)	-2.9%	
Catawba Project Costs	\$3.27	6.9%	Lower than budgeted O&M costs & year-end Duke benefits, insurance, and G&A true-up
Supplemental Power Costs	(\$2.84)	-10.1%	Higher purchases in January and July due to temperatures and increased capacity and transmission costs in June and July
Catawba Capital Additions	\$0.29	2.3%	
PMPA Capital Additions	\$1.33	71.3%	Primarily timing of Laurens Transmission line project
Other	\$0.05	0.1%	

Favorable >5%
Near Budget +/- 5%
Unfavorable < 5%

**PIEDMONT MUNICIPAL POWER AGENCY**  
**STATEMENT OF REVENUE & EXPENSE PER THE BOND RESOLUTION**  
**AS OF JULY 31, 2025**  
**(DOLLARS IN THOUSANDS)**

	CURRENT MONTH			YEAR TO DATE			
	ACTUAL	BUDGET	OVER(UNDER)	ACTUAL	BUDGET	OVER(UNDER)	%
<b>CATAWBA PROJECT:</b>							
CATAWBA POWER SALES							
Participant	\$14,844	\$14,859	(\$15)	\$102,482	\$101,372	\$1,110	1.1%
Duke-Exchange Energy	1,043	988	55	6,845	6,811	34	0.5%
Other-Surplus	107	155	(48)	5,186	3,838	1,348	35.1%
TOTAL	15,993	16,002	(9)	114,512	112,021	2,491	2.2%
CATAWBA POWER COSTS							
Operations & Maintenance	1,740	2,081	(341)	14,873	17,143	(2,270)	(13.2%)
Fuel Amort(Fuel Acct Deposit)	1,211	1,231	(20)	8,220	8,418	(198)	(2.4%)
Purch Power-Duke-McGuire Cap	21	21	0	142	143	(1)	(0.6%)
-McGuire Energy	1,068	1,001	67	6,704	6,741	(37)	(0.6%)
Customer Acct and G&A-Duke	770	758	12	5,093	5,308	(215)	(4.1%)
Customer Acct and G&A-Agency	470	561	(91)	2,689	3,177	(488)	(15.4%)
Property Tax Equivalent	835	835	0	5,846	5,844	2	0.0%
Tax Other-Duke	91	105	(14)	675	738	(63)	(8.5%)
TOTAL	6,206	6,593	(387)	44,241	47,512	(3,271)	(6.9%)
FUNDS AVAILABLE FROM OPERATIONS	9,787	9,409	378	70,270	64,509	5,761	8.9%
INTEREST INCOME	920	859	61	5,469	5,635	(166)	(2.9%)
MISCELLANEOUS INCOME(EXPENSE)	(548)	(677)	129	(4,300)	(4,736)	436	(9.2%)
FUNDS AVAILABLE FOR CAPITAL NEEDS	10,159	9,591	568	71,440	65,408	6,032	9.2%
OTHER AVAILABLE FUNDS							
Debt Service-Principal	0	0	0	66,565	66,565	0	0.0%
-Interest	9,301	9,308	(7)	20,254	20,254	0	0.0%
Reserve & Contingency - Capital Additions	1,044	1,314	(270)	12,373	12,665	(292)	(2.3%)
Fuel	259	581	(322)	5,186	9,370	(4,184)	(44.7%)
DEPOSITS							
Debt Service-Principal	2,255	2,255	0	15,788	15,787	1	0.0%
-Interest	4,738	4,738	0	32,861	32,860	1	0.0%
Reserve & Contingency	1,940	1,940	0	13,581	13,580	1	0.0%
Decommissioning	590	587	3	3,835	3,933	(98)	(2.5%)
Inventory	156	40	116	(248)	9	(257)	(2,856.2%)
PAYMENTS							
Debt Service-Principal	0	0	0	66,565	66,565	0	0.0%
-Interest	9,301	9,308	(7)	20,254	20,254	0	0.0%
Capital Additions	1,044	1,314	(270)	12,373	12,665	(292)	(2.3%)
Fuel	259	581	(322)	5,186	9,370	(4,184)	(44.7%)
TRANSFERS (TO) FROM							
Reserve & Contingency	0	0	0	0	0	0	0.0%
DSR Release/Special Transfers	0	0	0	0	0	0	0.0%
Catawba Working Capital	479	31	448	5,624	(761)	6,385	(839.0%)
Supplemental Working Capital	0	0	0	0	0	0	0.0%
WORKING CAP INCREASE(DECREASE)	\$479	\$31	\$448	\$5,624	(\$761)	\$6,385	(839.0%)

**PIEDMONT MUNICIPAL POWER AGENCY**  
**STATEMENT OF REVENUE & EXPENSE PER THE BOND RESOLUTION**  
**AS OF JULY 31, 2025**  
**(DOLLARS IN THOUSANDS)**

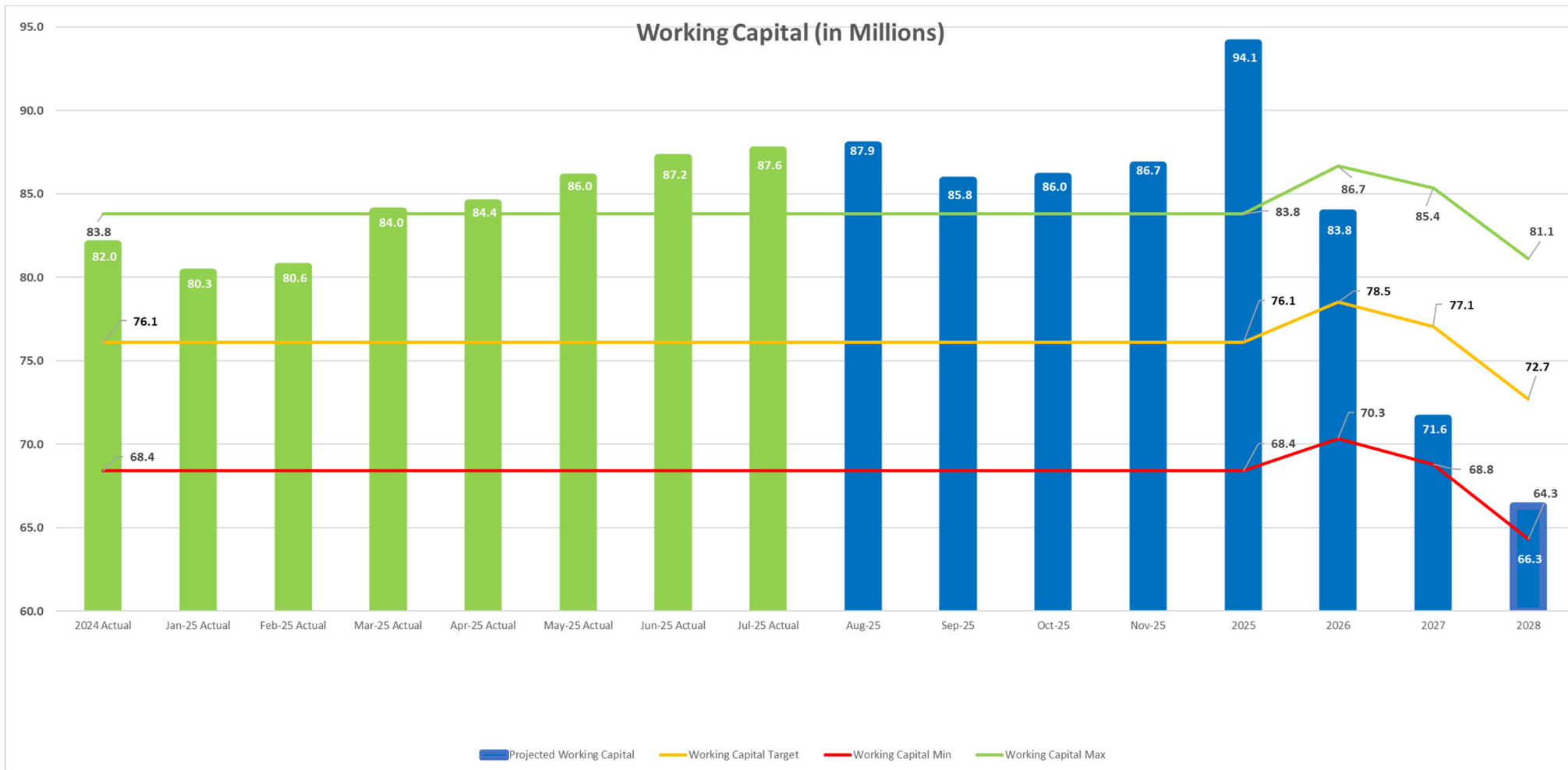
	CURRENT MONTH			YEAR TO DATE			
	ACTUAL	BUDGET	OVER(UNDER)	ACTUAL	BUDGET	OVER(UNDER)	%
<b>SUPPLEMENTAL:</b>							
SUPPLEMENTAL POWER SALES							
Participants-Supplemental Power	7,280	6,052	1,228	30,566	29,013	1,553	5.4%
-Leased Facilities	26	28	(2)	185	197	(12)	(6.3%)
-Other	121	103	18	741	774	(33)	(4.2%)
TOTAL	<u>7,427</u>	<u>6,183</u>	<u>1,244</u>	<u>31,492</u>	<u>29,984</u>	<u>1,508</u>	<u>5.0%</u>
SUPPLEMENTAL POWER COSTS							
Purch Power-Supp Capacity	1,008	924	84	6,310	6,192	118	1.9%
-Supp Energy	3,572	2,561	1,011	7,651	5,913	1,738	29.4%
Purch Power-Participants	1,181	1,143	38	7,446	7,579	(133)	(1.7%)
Purch Power-Other	383	344	39	1,955	1,583	372	23.5%
Transmission	1,110	795	315	6,434	5,519	915	16.6%
Transmission-Agency	0	4	(4)	24	29	(5)	(17.6%)
Leased Facilities-Duke	37	38	(1)	254	264	(10)	(3.9%)
Meter-Agency	0	1	(1)	94	107	(13)	(12.1%)
Customer Acct and G&A-Duke	0	0	0	0	0	0	0.0%
Customer Acct and G&A-Agency	125	151	(26)	715	854	(139)	(16.3%)
Property Tax Equivalent	9	9	0	61	63	(2)	(3.6%)
TOTAL	<u>7,425</u>	<u>5,970</u>	<u>1,455</u>	<u>30,944</u>	<u>28,103</u>	<u>2,841</u>	<u>10.1%</u>
FUNDS AVAILABLE FROM OPERATIONS	2	213	(211)	548	1,881	(1,333)	(70.9%)
MISCELLANEOUS INCOME(EXPENSE)	200	200	0	1,400	1,399	1	0.0%
FUNDS AVAILABLE FOR CAPITAL NEEDS	<u>202</u>	<u>413</u>	<u>(211)</u>	<u>1,948</u>	<u>3,280</u>	<u>(1,332)</u>	<u>(40.6%)</u>
PAYMENTS							
Debt Service-Interest	202	202	0	1,412	1,413	(1)	0.0%
Capital Additions-Transmission	0	210	(210)	190	1,473	(1,283)	(87.1%)
-LDMS/SCADA	0	0	0	326	341	(15)	(4.4%)
-General	0	1	(1)	19	53	(34)	(64.4%)
WORKING CAP INCREASE(DECREASE)	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>0.0%</u>

## PIEDMONT MUNICIPAL POWER AGENCY STATEMENT OF G&A EXPENSE AS OF JULY 31, 2025

CURRENT MONTH				YEAR TO DATE					
ACTUAL	BUDGET	OVER(UNDER)	%		ACTUAL	BUDGET	OVER(UNDER)	%	% ANNUAL BUDGET
				<b><u>G&amp;A-OFFICE EXPENSE</u></b>					
\$135,866	\$138,200	(\$2,334)	(1.7)	Payroll	\$932,111	\$982,800	(\$50,689)	(5.2)	51.8
8,352	8,100	252	3.1	Employer's FICA	72,204	77,000	(4,796)	(6.2)	62.8
19,470	19,200	270	1.4	Medical/Life Insurance	136,648	134,200	2,448	1.8	59.4
12,846	12,700	146	1.1	401A Plan	95,713	95,200	513	0.5	58.0
41	100	(59)	(59.0)	Subscriptions	966	800	166	20.8	48.3
355	1,100	(745)	(67.7)	Dues & Memberships	300,768	310,200	(9,432)	(3.0)	79.4
1,719	2,100	(381)	(18.1)	Utilities	12,139	14,700	(2,561)	(17.4)	48.6
1,396	1,400	(4)	(0.3)	Telephone	9,525	10,000	(475)	(4.8)	56.0
180	2,100	(1,920)	(91.4)	Office Supplies	2,882	14,700	(11,818)	(80.4)	11.5
0	200	(200)	(100.0)	Postage	559	1,100	(541)	(49.2)	28.0
0	100	(100)	(100.0)	Printing	293	700	(407)	(58.1)	14.7
198	1,300	(1,102)	(84.8)	Board & Staff Expenses	9,429	13,000	(3,571)	(27.5)	16.5
0	300	(300)	(100.0)	Miscellaneous	2,397	1,800	597	33.2	79.9
588	600	(12)	(2.0)	Equipment Rental	4,210	4,100	110	2.7	60.1
4,405	2,700	1,705	63.1	Maintenance-Building	27,487	82,800	(55,313)	(66.8)	26.9
17,604	12,200	5,404	44.3	Travel-Conf/Meetings	120,884	210,500	(89,616)	(42.6)	40.3
75	1,100	(1,025)	(93.2)	Travel-Training	5,957	24,500	(18,543)	(75.7)	19.9
5,001	3,000	2,001	66.7	Travel-Agency	16,699	21,000	(4,301)	(20.5)	46.4
0	0	0	0.0	Worker's Comp Insurance	4,604	5,000	(396)	(7.9)	92.1
0	0	0	0.0	Property Insurance	11,361	13,000	(1,639)	(12.6)	87.4
0	0	0	0.0	Liability Insurance	95,589	111,000	(15,411)	(13.9)	86.1
65,433	80,100	(14,667)	(18.3)	Bank & Rating Agency Fees	94,031	109,700	(15,669)	(14.3)	85.5
1,973	0	1,973	0.0	Annual Report	1,973	3,000	(1,027)	(34.2)	65.8
163,256	226,800	(63,544)	(28.0)	Economic Development	283,096	468,600	(185,504)	(39.6)	56.3
9,654	9,400	254	2.7	Telecommunications	65,446	65,800	(354)	(0.5)	57.9
0	500	(500)	(100.0)	Maintenance-Telecom	0	3,500	(3,500)	(100.0)	0.0
20,952	22,200	(1,248)	(5.6)	Computer Hardware/Software	316,594	308,300	8,294	2.7	78.6
<b>469,364</b>	<b>545,500</b>	<b>(76,136)</b>	<b>(14.0)</b>	<b>TOTAL G&amp;A OFFICE EXPENSE</b>	<b>2,623,565</b>	<b>3,087,000</b>	<b>(463,435)</b>	<b>(15.0)</b>	<b>57.5</b>
				<b><u>G&amp;A-OUTSIDE SERVICES</u></b>					
62,378	76,300	(13,922)	(18.2)	Legal	448,627	533,800	(85,173)	(16.0)	49.0
6,103	27,500	(21,397)	(77.8)	Engineering	133,286	192,500	(59,214)	(30.8)	40.4
0	0	0	0.0	Accounting	70,740	70,000	740	1.1	101.1
56,979	59,800	(2,821)	(4.7)	Financial	117,757	125,100	(7,343)	(5.9)	47.5
0	0	0	0.0	Administrative	8,120	5,000	3,120	62.4	162.4
83	2,500	(2,417)	(96.7)	Technology	1,133	16,900	(15,767)	(93.3)	3.9
<b>125,543</b>	<b>166,100</b>	<b>(40,557)</b>	<b>(24.4)</b>	<b>TOTAL G&amp;A OUTSIDE SERVICES</b>	<b>779,663</b>	<b>943,300</b>	<b>(163,637)</b>	<b>(17.3)</b>	<b>48.8</b>
<b>\$594,907</b>	<b>\$711,600</b>	<b>(\$116,693)</b>	<b>(16.4)</b>	<b>TOTAL OPERATING EXPENSE</b>	<b>\$3,403,228</b>	<b>\$4,030,300</b>	<b>(\$627,072)</b>	<b>(15.6)</b>	<b>55.3</b>
				<b><u>TRANSMISSION EXPENSE-AGENCY</u></b>					
\$0	\$4,000	(\$4,000)	(100.0)	Transmission Line Maintenance	\$23,908	\$29,000	(\$5,092)	(17.6)	47.8
0	1,000	(1,000)	(100.0)	Energy Efficiency/DSM	94,021	107,000	(12,979)	(12.1)	69.1
<b>\$0</b>	<b>\$5,000</b>	<b>(\$5,000)</b>	<b>(100.0)</b>	<b>TOTAL XMSN EXPENSE</b>	<b>\$117,929</b>	<b>\$136,000</b>	<b>(\$18,071)</b>	<b>(13.3)</b>	<b>63.4</b>

## PIEDMONT MUNICIPAL POWER AGENCY AS OF JULY 31, 2025

**After this month's operations, PMPA had \$87.6 million in working capital, which was \$6.4 million better than the YTD budget.**



22 JUL 2025

## **Fitch Affirms Piedmont Muni Power Agency, SC's Electric Refunding Revs at 'A-'; Outlook Stable**

Fitch Ratings - Austin - 22 Jul 2025: Fitch Ratings has affirmed the 'A-' ratings on the following Piedmont Municipal Power Agency, SC's (PMPA) revenue bonds:

--Approximately \$535.24 million electric revenue bonds.

The Outlook is revised to Stable from Negative.

The 'A-' rating reflects Fitch's evaluation of PMPA's eight largest of its 10 total participants, its take-or-pay contractual obligations related to the electric revenue bonds, and Fitch's assessment of PMPA's strong operating risk profile. PMPA's long-term Catawba project power supply agreements (PSAs) with its participants provide for a limited 25% step-up on the participant obligations in case of member default.

Fitch's rating factors a purchaser credit quality (PCQ) assessment of 'bbb', reflecting the midrange credit quality of several of the weaker project participants. Given the contractual framework, the PCQ is assessed at a level commensurate with the weakest members whose payment risk is not mitigated by the 25% step-up provision. The rating also reflects PMPA's operating risk assessment of 'a', which takes into consideration the solid performance of the Catawba facility and the relatively low cost of power, notwithstanding the nuclear concentration risk. These strengths provide a modest enhancement to the project's rating, allowing it to attain a rating of 'A-' despite only midrange purchaser credit quality. PMPA's financial profile is less of a consideration in the final determination of the PMPA rating given the contractual payment framework under the PSAs.

The Stable Outlook reflects a general trend of strengthening economic and financial metrics among many of the participants. Broad service area improvement is reflected in stronger customer growth and improved employment metrics. The participants' strong to very strong financial metrics are reflected in mostly positive trends in liquidity and net margin and modest overall debt levels.

### **SECURITY**

The bonds are secured by the net revenues of PMPA, including payments received from each of its 10 participants pursuant to their Catawba project PSAs. Fitch expects payments from the supplemental PSAs to terminate after 2029. However, the Catawba project PSAs will remain in effect and require each participant to pay for their share of Catawba project costs, which includes debt service on the PMPA bonds. The termination of the supplemental PSAs in 2029 consequently does not affect Fitch's rating of the PMPA bonds.

## KEY RATING DRIVERS

### Revenue Defensibility - 'bbb'

#### ***Strong Take-or-Pay Contracts with 25% Step-up;***

Revenue defensibility is midrange. Fitch's assessment of the purchaser credit quality (PCQ) at 'bbb' uses both Fitch's Portfolio Stress Model (PSM) and Fitch's evaluation of the credit quality of the eight largest participants, representing approximately 95% of the Catawba project entitlement share. The Catawba project PSAs are unconditional, take-or-pay obligations and include a step-up provision requiring each participant to purchase only up to 125% of its entitlement share if any participant defaults.

Fitch's PCQ assessment and the final rating are capped by the credit quality of the City of Rock Hill, SC electric system (Rock Hill), PMPA's largest project participant with a 28% entitlement share, since invoking the 125% contract step-up provisions following a Rock Hill default would not be sufficient to cover PMPA's obligations. However, Fitch's PCQ assessment and the final rating are currently constrained by the credit characteristics of other weaker members reviewed by Fitch.

The bonds mature in 2035, coinciding with the current PSAs for all 10 participants. The PMPA Board recently approved contract extensions for seven of the 10 Catawba participants through 2085. The project's Nuclear Regulatory Commission (NRC) license currently extends through 2043, well past the maturity of the bonds and the PSAs.

### Operating Risk - 'a'

#### ***Low Cost and Reliable Power Supply; Nuclear Concentration***

PMPA's strong operating risk assessment is driven by the project's strong operating history and low operating cost burden, which averaged approximately 5.7 cents/kWh during the past five years. The project's high-capacity factor and stable, low cost energy provide significant headroom for the assessment and are factored into the overall rating.

Concentration exists in PMPA's power supply, with nuclear generation accounting for approximately 90% of energy supply, net of the load served by Southeastern Power Administration (SEPA). Exposure to PMPA's owned interest in Catawba unit No. 2 is mitigated by reliability exchange agreements with Duke Energy Carolinas, LLC (DEC) and the co-owners of three other units DEC operates.

The Catawba project PSAs obligate the participants to pay debt service on the project bonds regardless of whether the project is operating or even operable.

### Financial Profile - 'aa'

#### ***Very Strong Financial Profile***

PMPA has historically maintained a very strong financial profile. Fitch expects PMPA's leverage to

decline further as the agency's debt continues to amortize. PMPA completed fiscal 2024 with a leverage ratio of 3.3x, which is essentially unchanged from the prior year but much lower than 2022 levels, and 227 days of cash on hand. This level of liquidity coupled with coverage of full obligations of 1.5x is neutral to the assessment.

However, the agency's very strong financial profile is less of a consideration in Fitch's determination of PMPA's rating given project costs are largely balanced and passed through to the purchasing utilities through the PSAs.

## **RATING SENSITIVITIES**

### **Factors that Could, Individually or Collectively, Lead to Negative Rating Action/Downgrade**

--A weakening in the credit quality of PMPA participants.

--Poor operating performance at the Catawba and McGuire nuclear generating units resulting in higher than anticipated power costs to the participants.

### **Factors that Could, Individually or Collectively, Lead to Positive Rating Action/Upgrade**

-- Improvement in participant credit quality could lead to positive rating action.

## **PROFILE**

PMPA is a public agency organized under the laws of the state of South Carolina. Ten South Carolina cities (participants) entered into long-term Catawba project PSAs and supplemental PSAs with PMPA. Under the Catawba project PSAs, each participant pays for its percentage share of the project operating and debt service expenses of PMPA on a take-or-pay basis, payable regardless of whether the Catawba project is operating or not. Payments from participants are considered an operating expense of their electric systems, satisfied ahead of any direct debt service of their electric systems.

PMPA's Catawba project consists of a 25% undivided ownership in the Catawba nuclear unit No. 2, entitling PMPA to approximately 277MW, which is operated by DEC. The risk of an extended outage of any one unit is shared among the four units through various reliability exchanges with the Catawba (units No. 1 and No. 2) and McGuire nuclear projects (units No. 1 and No. 2), providing some protection for the participants against single-unit outage at No. 2. The largest eight PMPA participants include the cities of Rock Hill (28.0%), Easley (13.2%), Newberry (10.5%), Gaffney (10.1%), Union (10.0%), Greer (9.3%), Clinton (7.8%), and Laurens (6.5%), all in South Carolina.

In addition to the Catawba project PSAs, PMPA and the participants signed supplemental PSAs that require PMPA to provide the participants with all-requirements bulk power supply, net of any SEPA allocations and any energy derived from each participant's generating capacity. PMPA supplies participant supplemental power supplies through an agreement with the South Carolina Public Service Authority (Santee Cooper; A-/Stable). At YE 2019, all 10 PMPA participants provided the required 10-year notice to terminate the supplemental PSAs, and in return, PMPA gave notice to terminate the

corresponding agreement with Santee Cooper. The final termination will occur in 2029, but Fitch does not expect it to affect the rating, which continues to be supported by the Catawba project PSAs.

## Sources of Information

In addition to the sources of information identified in Fitch's applicable criteria specified below, this action was informed by data from DIVER by Solve.

## REFERENCES FOR SUBSTANTIALLY MATERIAL SOURCE CITED AS KEY DRIVER OF RATING

The principal sources of information used in the analysis are described in the Applicable Criteria.

## ESG Considerations

The highest level of ESG credit relevance is a score of '3', unless otherwise disclosed in this section. A score of '3' means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. Fitch's ESG Relevance Scores are not inputs in the rating process; they are an observation on the relevance and materiality of ESG factors in the rating decision. For more information on Fitch's ESG Relevance Scores, visit <https://www.fitchratings.com/topics/esg/products#esg-relevance-scores>.

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## Rating Actions

ENTITY/DEBT	RATING	RECOVERY	PRIOR
Piedmont Municipal Power Agency (SC)			
<ul style="list-style-type: none"> <li>Piedmont Municipal Power Agency (SC) LT</li> </ul>	A- 	Affirmed	A- 
/Electric System Revenues/ 1 LT			

### RATINGS KEY OUTLOOK WATCH

POSITIVE		
NEGATIVE		
EVOLVING		
STABLE		

### Applicable Criteria

[Public Policy Revenue-Supported Entities Rating Criteria \(pub.12 Jan 2024\) \(including rating assumption sensitivity\)](#)

[U.S. Public Power Rating Criteria \(pub.24 Feb 2025\) \(including rating assumption sensitivity\)](#)

### Applicable Models

Numbers in parentheses accompanying applicable model(s) contain hyperlinks to criteria providing description of model(s).

Portfolio Stress Model, v1.11.1 [\(1\)](#)

## Additional Disclosures

### Solicitation Status

### Endorsement Status

Piedmont Municipal Power Agency (SC) EU Endorsed, UK Endorsed

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## PMPA Load-Side Generation Report

---

To: Board of Directors and Alternates  
 From: Mike Frazier *MTF*  
 Date: July 16, 2025

---

Santee Cooper called upon PMPA to run the Load-Side Generators on three days in June due to system conditions.

Load-Side Generation Operation during the month of June:

7 Jun. – 12:15 p.m. to 3:00 p.m. – 2.75 hrs.  
 24 Jun. – 3:00 p.m. to 9:00 p.m. – 6.00 hrs.  
 25 Jun. – 3:45 p.m. to 9:00 p.m. – 5.25 hrs.

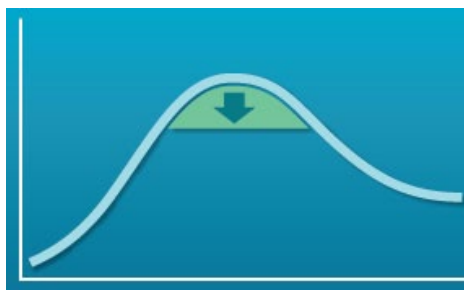
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TOTAL – 14.00 Hrs.

TOTAL YTD – 22.00 Hrs.

Load-side generation is called for during times of energy deficiency, adverse system conditions, or high economic energy prices.

Current Load-Side Generators are owned by the City of Clinton, Easley Combined Utilities, Gaffney Board of Public Works, Greer Commission of Public Works, and the City of Rock Hill.



# PMPA Demand Response System Report

To: Board of Directors and Alternates  
 From: Mike Frazier *MTF*  
 Date: July 16, 2025

23 Jun – 1:30 PM to 6:00 PM - 4.50 hrs      25 Jun – 1:30 PM to 6:00 PM - 4.50 hrs  
 24 Jun – 1:00 PM to 6:00 PM - 5.00 hrs

TOTAL 14.00 hours

PMPA Monthly Peak<sup>1</sup>: 555.8 MW @ Hour Ending 5:00 p.m. on Jun 25<sup>th</sup>

- Does NOT coincide with the Duke Energy Transmission Peak on Jun 25<sup>th</sup> @ Hour Ending 4:00 p.m.
- Monthly Maximum GSP Airport Temperature – 99° F on Jun 25<sup>th</sup> <sup>2</sup>

PMPA Total Participant Load <sup>3</sup>: 595.9 MW @ Hour Ending 5:00 p.m. on Jun 25<sup>th</sup>

PMPA Ratchet Quantity: 507.9 MW – based on Jul. 15, 2024 @ HE 5:00 p.m.

All loads are reflected at the transmission level, which includes 1.96% losses as of June 1, 2025.

<sup>1</sup> PMPA Monthly Peak – Used by Santee Cooper to determine PMPA’s capacity charge. This peak includes the load served by nine Participants (does not include Union) and generation (added back to the load) produced by the load-side generators. It also does not include Greer CPW’s load served from the leased Laurens EMC delivery points.

<sup>2</sup> This June was almost a repeat of last June with one caveat, more heat. Temperatures at GSP didn’t break 100 degrees Fahrenheit, but several days came close to it. The last ten days in June had high temperatures all in the nineties. Even with temperatures remaining in the double-digits, PMPA set its highest demand ever on June 25.

<sup>3</sup> PMPA Total Participant Load – includes load served by all ten Participants including the Greer CPW’s load served from leased Laurens EMC delivery points and generation produced by the load-side generators.

<u>Month</u>	<u>CDD</u>	<u>% of Normal</u>
Jun 2025	401	117
Normal	343	
Jun 2024	390	114

# ENERGY REPORT <sup>\*</sup>

Piedmont Municipal Power Agency

**JUNE, 2025**

**The Energy Authority (Surplus Energy Sold and Gross Revenue)**

<b>2,742</b>	<b>MWh</b>	<b>57,561</b>	<b>\$</b>	<b>20.99</b>	<b>\$ / MWh</b>
28,315	MWh - YTD	865,341	\$ - YTD	30.56	\$ / MWh - YTD

**Duke Energy (Surplus Energy Sold and Gross Revenue)**

<b>6,939</b>	<b>MWh</b>	<b>186,955</b>	<b>\$</b>	<b>26.94</b>	<b>\$ / MWh</b>
79,180	MWh-YTD	2,521,207	\$-YTD	31.84	\$ / MWh - YTD

**Santee Cooper (Surplus Energy Sold and Gross Revenue)**

<b>4,270</b>	<b>MWh</b>	<b>108,586</b>	<b>\$</b>	<b>25.43</b>	<b>\$ / MWh</b>
59,463	MWh-YTD	1,786,115	\$-YTD	30.04	\$ / MWh - YTD

**Total Surplus Sales Revenue**

<b>353,102</b>	<b>\$</b>		
5,172,663	\$ - YTD	166,958	MWh-YTD

**Generation Imbalance Charge .....**

<b>(66,663)</b>	<b>\$</b>
199,066	\$ - YTD

Deviation Band 1 - +/- 1.5%	Deviation Band 2 - Between +/-1.5% & 7.5%	Deviation Band 3 - Greater than +/- 7.5%
(\$10,771)	(\$27,575)	(\$28,318)

**Energy Imbalance Charge .....**

<b>(111)</b>	<b>\$</b>
93,194	\$ - YTD

Deviation Band 1 - +/- 1.5%	Deviation Band 2 - Between +/-1.5% & 7.5%	Deviation Band 3 - Greater than +/- 7.5%
(\$3,103)	\$2,992	\$0

**Supplemental Energy Purchased .....**

Santee Cooper	TEA Backstand <sup>&amp;</sup>	Total	
39,476	5	<b>39,481</b>	<b>MWh</b>
65,944	7,974	73,918	MWh - YTD
2,069,065	92	<b>2,069,156</b>	<b>\$</b>
3,563,057	421,786	3,984,843	\$ - YTD
52.41	18.34	<b>52.41</b>	<b>\$ / MWh</b>
54.03	52.90	53.91	\$ / MWh - YTD

<sup>\*</sup> All MWh are measured at the bus bar (generation level)

<sup>&</sup> Includes energy and transmission costs



## PMPA Load-Side Generation Report

---

To: Board of Directors and Alternates  
 From: Mike Frazier *MTF*  
 Date: August 13, 2025

---

Santee Cooper called upon PMPA to run the Load-Side Generators on two days in July due to system conditions.

Load-Side Generation Operation during the month of June:

12 Jul. – 3:00 p.m. to 6:00 p.m. – 3.00 hrs.

21 Jul. – 3:15 p.m. to 8:00 p.m. – 4.75 hrs.

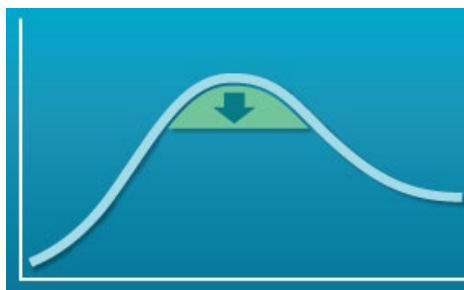
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TOTAL – 7.75 Hrs.

TOTAL YTD – 29.75 Hrs.

Load-side generation is called for during times of energy deficiency, adverse system conditions, or high economic energy prices.

Current Load-Side Generators are owned by the City of Clinton, Easley Combined Utilities, Gaffney Board of Public Works, Greer Commission of Public Works, and the City of Rock Hill.



# PMPA Demand Response System Report

To: Board of Directors and Alternates  
 From: Mike Frazier *MTF*  
 Date: August 13, 2025

7 Jul – 3:00 PM to 6:00 PM - 3.00 hrs      27 Jul – 3:00 PM to 7:00 PM - 4.00 hrs  
 8 Jul – 2:00 PM to 6:00 PM - 4.00 hrs      28 Jul – 12:00 PM to 6:00 PM - 6.00 hrs  
 9 Jul – 3:00 PM to 6:00 PM - 3.00 hrs      29 Jul – 3:00 PM to 4:30 PM - 1.50 hrs  
 21 Jul – 2:30 PM to 6:00 PM - 3.50 hrs

TOTAL 25.00 hours

PMPA Monthly Peak<sup>1</sup>: 544.9 MW @ Hour Ending 4:00 p.m. on Jul 28<sup>th</sup>

- Does NOT coincide with the Duke Energy Transmission Peak on Jul 8<sup>th</sup> @ Hour Ending 5:00 p.m.
- Monthly Maximum GSP Airport Temperature – 100° F on Jul 26<sup>th</sup>, 27<sup>th</sup>

PMPA Total Participant Load<sup>3</sup>: 584.4 MW @ Hour Ending 4:00 p.m. on Jul 28<sup>th</sup>

PMPA Ratchet Quantity: 527.9 MW – based on Jun. 25, 2025 @ HE 5:00 p.m.

All loads are reflected at the transmission level, which includes 1.96% losses as of June 1, 2025.

<sup>1</sup> PMPA Monthly Peak – Used by Santee Cooper to determine PMPA’s capacity charge. This peak includes the load served by nine Participants (does not include Union) and generation (added back to the load) produced by the load-side generators. It also does not include Greer CPW’s load served from the leased Laurens EMC delivery points.

<sup>2</sup> Every day in July had temperatures reaching ninety degrees F or above. For two consecutive days, temperatures hit one-hundred degrees F. Fortunately, those days were over a weekend when PMPA loads are lower than on weekdays. For the month, temperatures averaged far above normal. Even with the extra heat in July, PMPA did not reach a new all-time peak, which was set last month.

<sup>3</sup> PMPA Total Participant Load – includes load served by all ten Participants including the Greer CPW’s load served from leased Laurens EMC delivery points and generation produced by the load-side generators.

<u>Month</u>	<u>CDD</u>	<u>% of Normal</u>
Jul 2025	570	125
Normal	457	
Jul 2024	518	113

# ENERGY REPORT <sup>\*</sup>

Piedmont Municipal Power Agency

**JULY, 2025**

## The Energy Authority (Surplus Energy Sold and Gross Revenue)

<b>37</b>	<b>MWh</b>	<b>1,100</b>	<b>\$</b>	<b>29.73</b>	<b>\$ / MWh</b>
28,352	MWh - YTD	866,441	\$ - YTD	30.56	\$ / MWh - YTD

## Duke Energy (Surplus Energy Sold and Gross Revenue)

<b>2,207</b>	<b>MWh</b>	<b>74,510</b>	<b>\$</b>	<b>33.76</b>	<b>\$ / MWh</b>
81,387	MWh-YTD	2,595,717	\$-YTD	31.89	\$ / MWh - YTD

## Santee Cooper (Surplus Energy Sold and Gross Revenue)

<b>2,074</b>	<b>MWh</b>	<b>48,081</b>	<b>\$</b>	<b>23.18</b>	<b>\$ / MWh</b>
61,537	MWh-YTD	1,834,196	\$-YTD	29.81	\$ / MWh - YTD

## Total Surplus Sales Revenue

<b>123,691</b>	<b>\$</b>			
5,296,354	\$ - YTD	171,276	MWh-YTD	

## Generation Imbalance Charge .....

<b>(1,752)</b>	<b>\$</b>
269,305	\$ - YTD

Deviation Band 1 - +/- 1.5%	Deviation Band 2 - Between +/-1.5% & 7.5%	Deviation Band 3 - Greater than +/- 7.5%
(\$1,265)	(\$487)	\$0

## Energy Imbalance Charge .....

<b>(10,102)</b>	<b>\$</b>
83,093	\$ - YTD

Deviation Band 1 - +/- 1.5%	Deviation Band 2 - Between +/-1.5% & 7.5%	Deviation Band 3 - Greater than +/- 7.5%
(\$10,147)	\$45	\$0

## Supplemental Energy Purchased .....

Santee Cooper	TEA Backstand <sup>&amp;</sup>	Total	
65,293	0	<b>65,293</b>	<b>MWh</b>
131,237	7,974	139,211	MWh - YTD
3,509,712	0	<b>3,509,712</b>	<b>\$</b>
7,074,681	421,786	7,496,467	\$ - YTD
53.75	---	<b>53.75</b>	<b>\$ / MWh</b>
53.91	52.90	53.85	\$ / MWh - YTD

<sup>\*</sup> All MWh are measured at the bus bar (generation level)

<sup>&</sup> Includes energy and transmission costs

Catawba and McGuire Report – August 14, 2025

Since the last Board meeting, Catawba Unit 1, Catawba Unit 2, McGuire Unit 1, and McGuire Unit 2 have operated continuously without any concerns.

<u>July 2025</u>	<u>Capacity Factor</u>	<u>Generation (MWhs)</u>	<u>PMPA's Entitlement (MWhs)</u>
Catawba 1	100.24%	865,071	54,067
Catawba 2	98.89%	846,141	52,884
McGuire 1	99.80%	859,869	52,151
McGuire 2	99.28%	855,375	51,878

2025 & 2026 Planned Refueling Outages

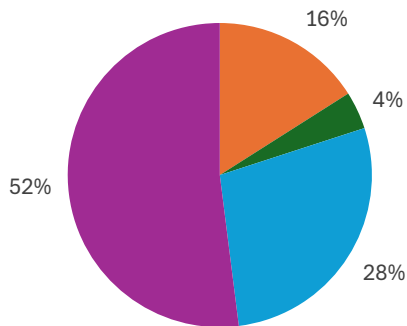
<u>Unit</u>	<u>Outage Start Date</u>	<u>Budgeted Duration</u>
Catawba 2	September 3, 2025	34.5 Days
McGuire 2	March 21, 2026	28 Days
Catawba 1	April 18, 2026	25 Days
McGuire 1	September 5, 2026	28 Days

Nuclear Regulatory Commission

Catawba's NRC Regulatory Performance Indicators are Green with no regulatory issues.

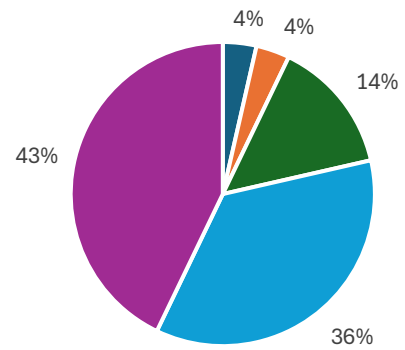
## 2025 Power Conference Survey Results

### Hotel Check-in - 2025



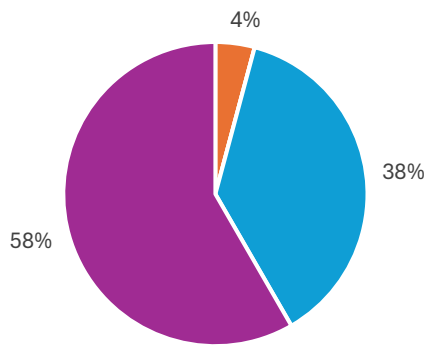
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

### Hotel Check-in - 2024



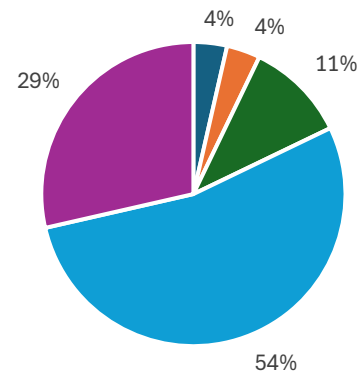
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### Hotel Rooms - 2025



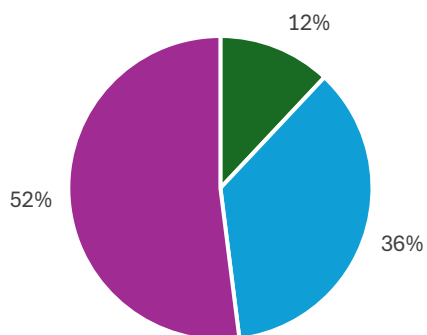
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

### Hotel Room - 2024



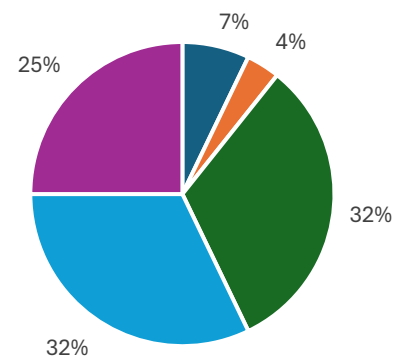
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

### Meeting Room - 2025



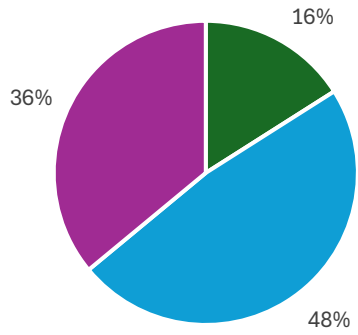
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

### Meeting Room - 2024



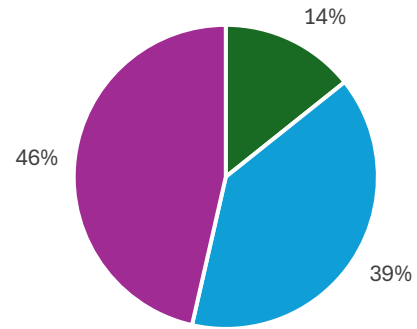
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Meals - 2025



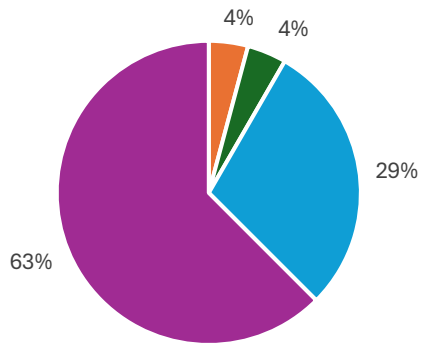
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Meals - 2024



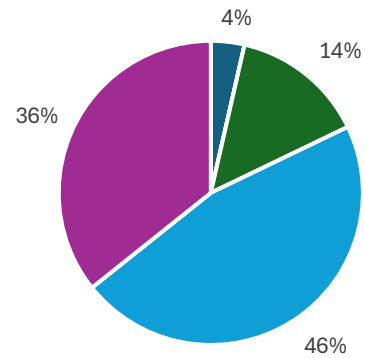
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Overall Service - 2025



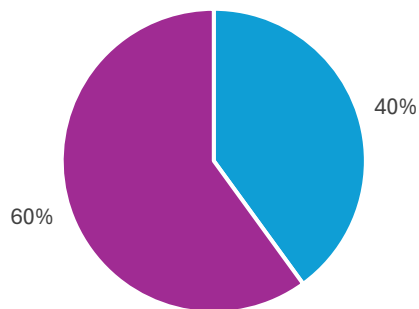
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Overall Service - 2024



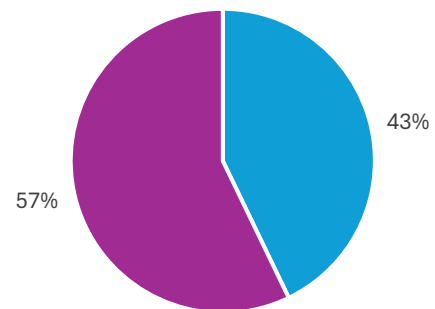
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Conference Schedule - 2025



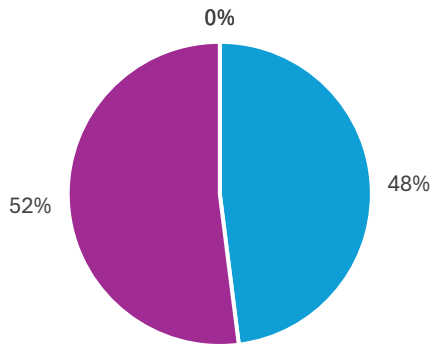
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Conference Schedule - 2024



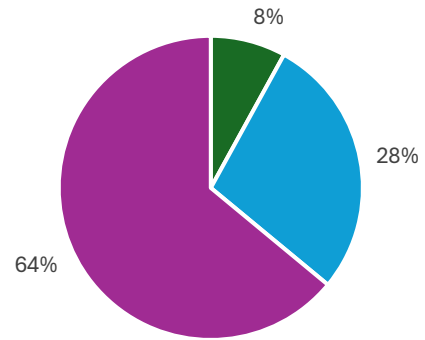
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Quality of Speakers - 2025



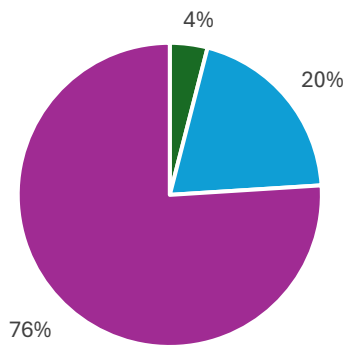
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Quality of Speakers - 2024



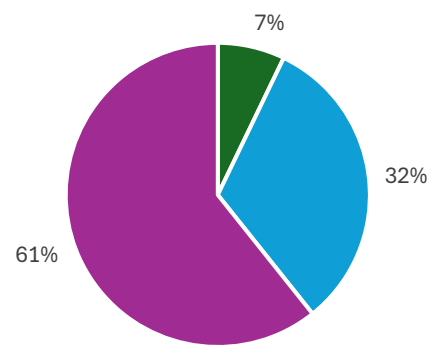
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Overall Conference - 2025



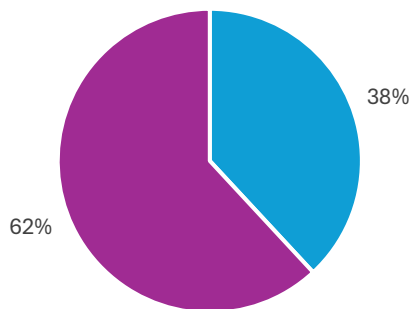
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Overall Conference - 2024



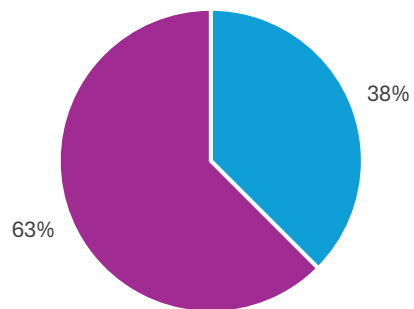
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Online Registration - 2025



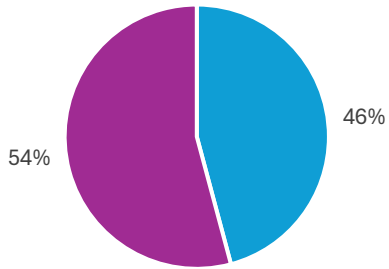
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Online Registration - 2024



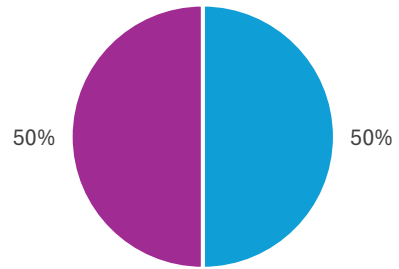
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Conference Information Website - 2025



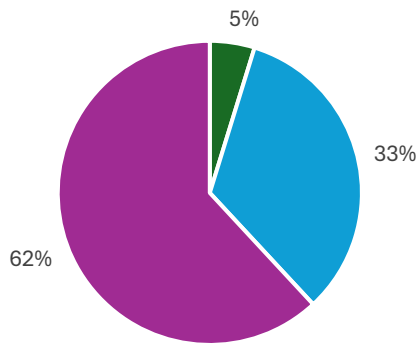
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Conference Information Website - 2024



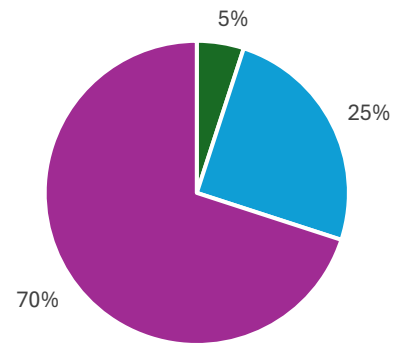
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Mobile App - 2025



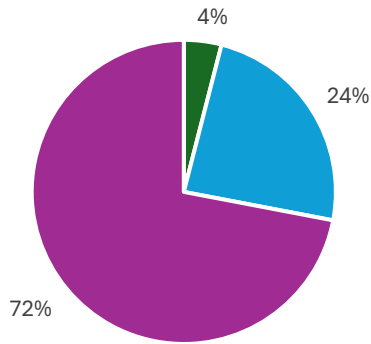
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Mobile App - 2024



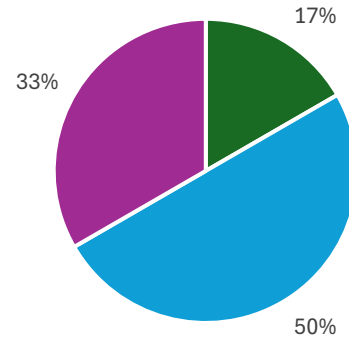
■ 1 = Very Dissatisfied ■ 2 ■ 3 = Neutral ■ 4 ■ 5 = Very Satisfied

Joel Ledbetter - 2025



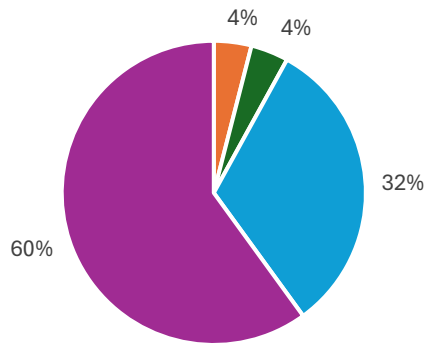
■ 1 = Very Dissatisfied ■ 2 = Neutral ■ 3 = Very Satisfied

Rep. Neal Collins - 2025



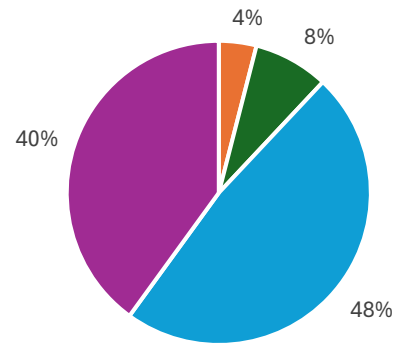
■ 1 = Very Dissatisfied ■ 2 = Neutral ■ 3 = Very Satisfied

Jack Jacobson - 2025



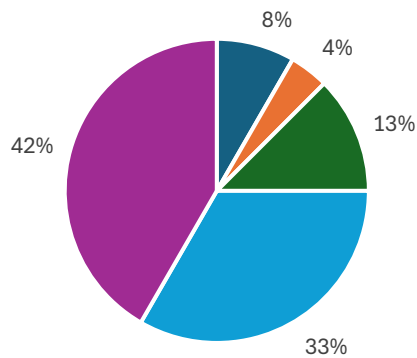
■ 1 = Very Dissatisfied ■ 2 = Very Satisfied ■ 3 = Neutral ■ 4 = Very Satisfied

Katherine Elrod - 2025



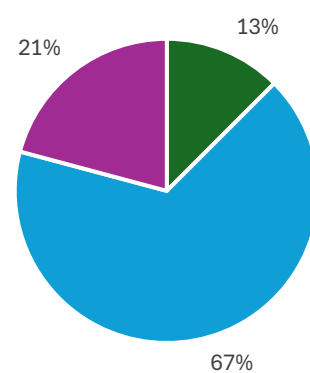
■ 1 = Very Dissatisfied ■ 2 = Very Satisfied ■ 3 = Neutral ■ 4 = Very Satisfied

Sunny Wescott - 2025



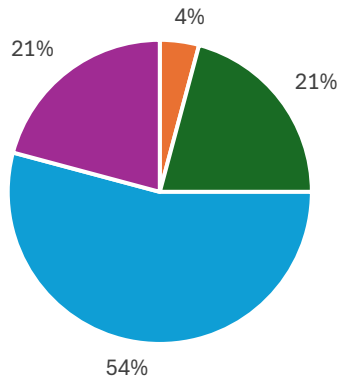
■ 1 = Very Dissatisfied ■ 2 = Very Satisfied ■ 3 = Neutral ■ 4 = Very Satisfied ■ 5 = Very Satisfied

Nicole Cervi - 2025



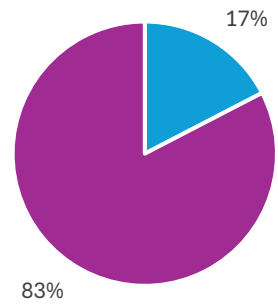
■ 1 = Very Dissatisfied ■ 2 = Neutral ■ 3 = Very Satisfied

Joe Witkowski - 2025



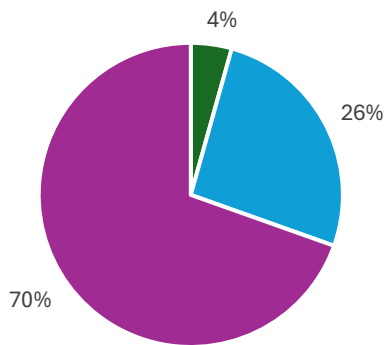
■ 1 = Very Dissatisfied ■ 2 = Very Dissatisfied ■ 3 = Neutral ■ 4 = Very Satisfied

Participant Roundtable Discussion - 2025



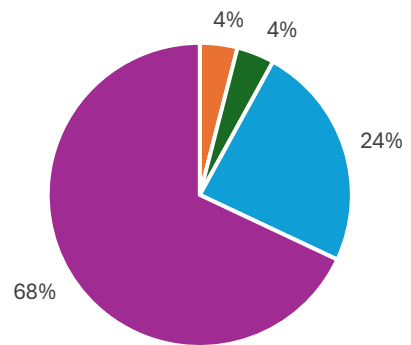
■ 1 = Very Dissatisfied ■ 2 = Very Dissatisfied ■ 3 = Neutral ■ 4 = Very Satisfied

Dennis Cameron - 2025



■ 1 = Very Dissatisfied ■ 2 = Very Dissatisfied ■ 3 = Neutral ■ 4 = Very Satisfied

Joel Ledbetter - 2025 (Day 2)



■ 1 = Very Dissatisfied ■ 2 = Very Dissatisfied ■ 3 = Neutral ■ 4 = Very Satisfied

**Hotel Comments**

- Something as simple as no Kleenex, no conditioner
- Had to change rooms due to the first room being dirty. Elevators continue to be an issue. Room was never cleaned during the entire trip. Had to go in search of towels etc. every day. Lobby area was hot & humid for the whole trip. Pool closes way to early for beach resort during the summer.
- I love the hotel primarily due to the all suits rooms, views at every turn on the hotel etc. I know there are newer but don't lose the things that work somewhere else.
- Check in seems to always have some issues...
- Great hotel. Never leave this spot
- Needs more/bigger elevators
- Need more handicap parking
- Waited over an hour for our room to be ready. They also did not even consider a request for a room on the north side of the hotel. Food has been OK, not great.
- Cold in the meeting room.
- This year was as good as any

**Conference Comments**

- Mrs. Sunny knocked a home run. She was amazing! All the other speakers were good, and informative.
- A couple of speakers had decent content but overall was not the strongest line-up.
- Good job to PMPA for planning and the conference itself.
- Good info across the conference.
- Great job! I enjoyed it!
- The audio was better than in past years but I still had some trouble hearing the people speaking. I sat in the second row near the middle. This could be caused by the room so I am not sure if the audio can be improved.
- Could have done without the meteorologist.
- Every session was very informative
- Sunny was fantastic and information that people really need to hear. For the most part all of the speakers were able to communicate their point and how it relates to member cities effectively.

**Speaker Comments**

- Good variety.
- Please never invite that Sunny Westcott woman again.
- Good info on all sessions on Saturday. Joel's topic today should have been the after lunch topic for Friday so more participants could have heard the details.
- AI presentation was hard to follow and understand

**Registration & Mobile App Comments**

- Good experience
- Good job PMPA
- Great!

**Are there any topics you wish had been included that were not covered?**

- Not really
- Perhaps someone who speaks on working together and team works and being on the same team.
- I thought this was a good mix of topics and information. Encourage you to continue along the same lines.
- Like more local and state topics
- I would have liked to have heard from Abbeville about the hydroplant and how Helene impacted it.

**Overall, the Conference could be improved by:**

- The temp in the room was a bit chilly each day.
- I think it is good as it is.
- A brief financial review by our Finance Director. Just some highlights coming from that person.
- Nothing to suggest.
- I know the audio and visual guys do a great job. There was a little echo in the room this year that I never noticed in the past.
- Vet the speakers just a little more. Make sure they understand what 50 minutes actually is...

**Other comments/suggestions**

- Great speakers, but a diverse group of speakers would be awesome.
- Greatly appreciate the PMPA staff and their work to make this happen.
- Really well done. Thank you!
- Joel is an amazing resource and was very helpful to our group. Perhaps some panel type q&a time with just him for whatever others are dealing with. He took time out of his personal time to help us with a time sensitive issue.

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PMPA  
Board of Directors Meeting

**EEA Alerts**

August 21, 2025

# Duke Energy – Energy Alerts

Why have an energy alert system?

## **Winter Storm Elliott**

2022 – Christmas Eve

7° F Low recorded at GSP

High only reached 28 ° F

LSG ran 6:00 am – 11:00 am



# Duke Energy – Energy Alerts

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## What is the Duke Energy Alert System?

A way “... to improve communications about energy and capacity constraints for its [Duke Energy] network and wholesale customers. The communications, known as Energy Emergency Alerts, are based on the escalation order and notifications used by Reliability Coordinators, Balancing Authorities and Transmission Operators.”

# Duke Energy – Energy Alerts

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## Warning – Issue a Capacity / Energy Warning

“Issued the day prior to [or day of] a potential event for situational awareness and requires no action.

Unless other escalated messages are issued, the only additional message would be to terminate the warning.”

# Duke Energy – Energy Alerts

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## Warning – Issue a Capacity / Energy Warning

Issued June 20, 2025 @ 2:10 PM [Friday]

“Duke Energy Carolinas is declaring a warning condition for impending high loads from 13:00 - 22:00 daily beginning Monday, 06/23/2025 through Thursday, 06/26/2025.

There is a higher probability of further escalation, but we are not requesting any actions by Load Serving Entities at this time.

Please monitor communication channels for further messages in the event conditions change and call your Wholesale Account Manager with any questions.  
Description: Week of June 26, 2025”

# Duke Energy – Energy Alerts

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## Energy Emergency Alert 1 [EEA1]

“Issued at or immediately prior to an event and will require some responsive actions. A separate EEA message will include a specific end time. Other escalated messages may follow.”

Duke is **requesting** Load Serving Entities to implement Demand Response programs and Distributed Energy Resources assistance.

# Duke Energy – Energy Alerts

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## Energy Emergency Alert 1 [EEA1]

Issued June 23, 2025 @ 11:06 AM [Monday]

“Duke Energy Carolinas has entered an EEA1 (all available generation resources in use) condition. **We are requesting Load Serving Entities to implement Demand Response programs and Distributed Energy Resources assistance.** We will send further notifications, including termination of this EEA when conditions warrant. Please monitor communication channels for further messages in the event conditions change and call your Wholesale Account Manager with any questions.

Description: DEC BA declares EEA Level 1 at 1100.”

# Duke Energy – Energy Alerts

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## Energy Emergency Alert 2 [EEA2]

“Issued at or immediately prior to an event and will require some responsive actions. A separate EEA message will include a specific end time. Escalated or de-escalated messages may follow.”

Duke is **directing** all Load Serving Entities to implement all available Demand Response programs, and Distributed Energy Resource assistance, to curtail all non-firm energy sales, to curtail all non-essential loads and run all behind the delivery point meter generation.

# Duke Energy – Energy Alerts

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## Energy Emergency Alert 2 [EEA2]

Issued June 23, 2025 @ 7:07 PM [Monday]

“Duke Energy Carolinas has entered an EEA2 (load management procedures in effect) condition. **Load serving entities are directed to implement all available Demand Response programs, and Distributed Energy Resource assistance, to curtail all non-firm energy sales, to curtail all non-essential loads and run all behind the delivery point meter generation.** We will send further notifications, including termination of this EEA, when conditions warrant. Please monitor communication channels for further messages in the event conditions change and call your Wholesale Account Manager with any questions.

Description: Notification callout created by Nathan D. Smock for Notifications CW on Mon 06/23/2025 19:05:34 ET”

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# Duke Energy – Energy Alerts

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Run Load-side Generation (if not already)?

Run Standby Generation?

Who pays for that?

Should it be a socialized cost?

# Duke Energy – Energy Alerts

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As Duke Energy Carolinas is the Transmission Provider and the Reliability Coordinator for VACAR South (the Carolinas), Load Serving Entities are Required to follow its Directives.

# Duke Energy – Energy Alerts

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## Energy Emergency Alert 3 [EEA3]

“Issued at or immediately prior to an event and will require some responsive actions. A separate EEA termination message will include a specific end time. A de-escalated message may follow.”

This has not happened since Duke started the alert system.

# Duke Energy – Energy Alerts

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## Energy Emergency Alert 3 [EEA3]

“Duke Energy has entered an EEA3 (firm load interruption is imminent or in progress) condition [i.e. **Rolling Blackouts**]. If not previously directed, Load Serving Entities are directed to implement all available Demand Response programs, Distributed Energy Resources Assistance, to curtail all non-firm energy sales, and to implement a voltage reduction, where possible. Additionally, Load Serving Entities are directed to **implement firm load shed** equal to (%) of total as soon as possible. Further notifications, including termination of this EEA, will be sent when conditions warrant.”

## Duke Energy – Energy Alerts

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Is Your Utility Ready To Drop 5% of its Load?

10% ?

15% ?

20% ?

What is your load shedding plan?

# Duke Energy – Energy Alerts

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## Energy Emergency Alert 1 [EEA1]

Issued June 23, 2025 @ 7:50 PM [Monday]

“Duke Energy Carolinas has entered an EEA1 (all available generation resources in use) condition. We are requesting Load Serving Entities to implement Demand Response programs and Distributed Energy Resources assistance. We will send further notifications, including termination of this EEA when conditions warrant. Please monitor communication channels for further messages in the event conditions change and call your Wholesale Account Manager with any questions.

Description: Notification callout created by Nathan D. Smock for Notifications CW on Mon 06/23/2025 19:49:18 ET

# Duke Energy – Energy Alerts

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## Energy Emergency Alert 0 [EEA0] - Termination

“Will be issued prior to termination of the EEA event, allowing the end of previously requested/directed actions. Other escalated or de-escalated messages may follow if the event warning continues.”

# Duke Energy – Energy Alerts

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## Energy Emergency Alert 0 [EEA0] - Termination

Issued June 23, 2025 @ 9:34 PM [Monday]

“Duke Energy Carolinas has entered an EEA Level 0 condition as of 22:00 on 06/23/2025. This message terminates all previously declared EEA conditions for Duke Energy Carolinas. Load Serving Entities are free to cease all previously requested/directed actions (demand response, Distributed Energy Resource assistance, curtailment of sales and/or non-essential loads, voltage reductions, and firm load shed) and return to normal operations. Please monitor communication channels for further messages in the event conditions change and call your Wholesale Account Manager with any questions. The Capacity/Energy Warning continues to remain in effect for Duke Energy Carolinas through 22:00 on 06/26/2025...”

## Duke Energy – Energy Alerts

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Staff suggests PMPA establish a policy for notification and the reduction of load in the event of declared energy emergencies.

This can be developed by the Supplemental Power Supply/Transmission Committee and brought to the full PMPA Board for approval.

# Catawba Nuclear Station Power Uprate

Dennis Cameron  
August 21, 2025

# Catawba Power Uprate

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- More than 170 power uprates have been performed across the US commercial nuclear sector dating back to 1977
  - Measurement uncertainty recapture (MUR) power uprates – increased the licensed power by less than 2 percent by implementing improved techniques for calculating reactor power
  - Stretch power uprates – typically between 2 and 7 percent, involves changes to instrumentation but not major plant modifications
  - Extended power uprates – have been approved for increases as high as 20 percent, usually require significant modifications to major pieces of equipment
  - Catawba Unit 1, McGuire Unit 1, and McGuire Unit 2 previously implemented the MUR uprates earlier prior to 2015

# Capital Power Uprate - continued

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- Evaluation studies have determined the feasibility and cost effectiveness to implement additional power uprates for McGuire Unit 1, McGuire Unit 2, and Catawba Unit 1
- Duke has decided, with management approval, to move forward with the power uprates at both McGuire Units
- Increase Output of 75 MWs per unit or 150 MWs for the McGuire station
- Implementation will be Fall 2029 for McGuire Unit 1 and Fall 2030 for McGuire Unit 2

# Catawba Power Uprate - continued

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- Evaluation studies also show the feasibility of uprating Catawba Unit 1 by 75 MWs
- Catawba Unit 2 cannot be uprated due to the thermal margin limitations associated with the Steam Generators
- Proposed implementation of Catawba Unit 1 uprate would be in Spring 2031
- With the proposed uprates for McGuire Unit 1, McGuire Unit 2, and Catawba Unit 1; PMPA would gain additional 13.785 MWs

# Catawba Power Uprate - continued

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- Cost Estimate for Catawba Unit 1 Uprate
  - \$416 million includes \$33 million of contingency and \$175 million of equipment that is to be replaced due to end of service life
  - Uprate costs \$241 million
- Cost Estimate – PMPA's Share
  - \$30.13 million or \$2,185 per kw with contingency
  - \$26 million or \$1,886 per kw excluding contingency

# Uprate vs Supplemental Power Costs (Combined Cycle)

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- Uprate of 13.785 MWs
  - Capital investment of \$2,185/kw
  - No increase in O&M
  - Incremental fuel costs for additional energy
  
  - Combined Cycle \$2,140/kw
  - Fixed O&M \$1.75/kw-month
  - Variable O&M \$2/MWh
  - Gas price \$4-\$5/mmbtu

# Uprate vs Supplemental Power Costs (Combined Cycle) - continued

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- 2031 Uprate will result in a NPV savings of \$23 million for the current license period
- For the period 2031 to 2063 will result in a NPV savings of \$45 million

# Duke Notification

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- Duke notified PMPA on June 3, 2025
- Request for approval to move forward with the License Amendment Application (LAR) process
- The estimate for this process is \$77.6 million
  - PMPA's share is \$9.7 million
- PMPA has until August 31, 2025 to decide if it wants to participate in the Uprate project

# Catawba Power Uprate - continued

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- Next Steps
  - Approve and keep the MWs for PMPA's use
  - Management Recommendation - Approve the Power Uprate Project and move forward with finalizing a Capital Additions Agreement with Duke
  - If Board decides not to approve the Power Uprate Project, then reach an agreement with Duke to pay for PMPA's share of the project and rights to the additional output

**UNITED STATES OF AMERICA BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

<b>Duke Energy Corporation</b>	)	
<b>Duke Energy Carolinas, LLC</b>	)	<b>Docket No. EC25-___-000</b>
<b>Duke Energy Progress, LLC</b>	)	

**APPLICATION UNDER SECTION 203 OF THE FEDERAL POWER ACT FOR  
APPROVAL OF INTERNAL CORPORATE REORGANIZATION**

Duke Energy Corporation (“Duke Energy”), together with its wholly-owned public utility operating company, Duke Energy Carolinas, LLC (“DEC”), and its indirectly wholly-owned public utility operating company, Duke Energy Progress, LLC (“DEP,” together with DEC, “the Companies,” and collectively, with Duke Energy, “the Applicants”), hereby submit this application for authorization of a proposed internal corporate reorganization (the “Internal Reorganization”) pursuant to sections 203(a)(1) and 203(a)(2) of the Federal Power Act (“FPA”)<sup>1</sup> and Part 33 of the regulations of the Federal Energy Regulatory Commission (“FERC” or “Commission”),<sup>2</sup> in which DEP will merge with and into DEC, with DEC as the surviving entity. As a result, a single utility will serve all of the existing wholesale and retail customers in the legacy DEC and DEP service territories.

As described in detail in this application, the Internal Reorganization is consistent with the public interest and meets the statutory requirements of FPA section 203. Specifically, the Internal Reorganization should be approved because it is consistent with the public interest under criteria

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<sup>1</sup> 16 U.S.C. §§ 824b(a)(1)-(2) (2018). Duke Energy is the parent holding company and is not itself a public utility. Duke Energy joins this application solely out of an abundance of caution to the extent that the Commission deems the Internal Reorganization requires approval under FPA section 203(a)(2) for Duke Energy or any intermediate holding companies in the Duke Energy system that play a role in facilitating the merger of DEP and DEC.

<sup>2</sup> 18 C.F.R. Part 33 (2025).

outlined by the Commission in its regulations, in the *Merger Policy Statement*<sup>3</sup> and the *Supplemental Merger Policy Statement*,<sup>4</sup> and in Order No. 669.<sup>5</sup> Applicants therefore respectfully request that the Commission grant the authorizations requested herein and grant limited waivers of certain Part 33 filing requirements.<sup>6</sup>

Contemporaneously with filing this application with FERC, the Companies are also filing applications seeking approval of the Internal Reorganization with the North Carolina Utilities Commission (“NCUC”), which oversees the Companies’ North Carolina retail jurisdiction, and the Public Service Commission of South Carolina (“PSCSC”), which oversees the Companies’ South Carolina retail jurisdiction.<sup>7</sup> The Applicants are requesting regulatory approval from all

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<sup>3</sup> *Inquiry Concerning the Commission’s Merger Pol’y Under the Fed. Power Act: Pol’y Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996), 61 Fed. Reg. 68,595 (1996) (“*Merger Policy Statement*”), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997).

<sup>4</sup> *FPA Section 203 Supplemental Pol’y Statement*, 120 FERC ¶ 61,060 (2007) (“*Supplemental Merger Policy Statement*”), *order on clarification and consideration.*, 122 FERC ¶ 61,157 (2008).

<sup>5</sup> *See Transactions Subject to FPA Section 203*, Order No. 669, 113 FERC ¶ 61,315 (2005), *order on reh’g*, Order No. 669-A, 115 FERC ¶ 61,097, *order on reh’g*, Order No. 669-B, 116 FERC ¶ 61,076 (2006).

<sup>6</sup> On May 30, 2025, DEC, DEP, and Duke Energy Indiana, LLC (“DEI”) jointly filed a petition for declaratory order requesting that the Commission make certain findings so that DEC, DEP, and DEI may each establish a wholly-owned procurement company (“ProCo”) subsidiary (“DEC ProCo,” “DEP ProCo,” and “DEI ProCo,” respectively) to achieve customer rate savings through increased tax efficiencies. Petition for Declaratory Order, Blanket Authorizations, and Waivers, Docket No. EL25-89-000 (filed May 30, 2025) (“Petition”). In the Petition, DEC, DEP, and DEI requested that the Commission find, *inter alia*, that DEC ProCo, DEP ProCo, and DEI ProCo are not public utilities under FPA section 201, 16 U.S.C. § 824. That same day, DEC and DEP submitted proposed changes to the Duke Energy Joint Open Access Transmission Tariff (“Joint OATT”) to account for the establishment of DEC ProCo and DEP ProCo. Revisions to Joint OATT, Docket No. ER25-2385-000 (filed May 30, 2025). As of today, the Petition and proposed Joint OATT revisions remain pending. Should the Commission make the determinations requested in the Petition and accept the Joint OATT changes, Applicants anticipate that DEC ProCo and DEP ProCo will be fully operational when the Internal Reorganization is consummated and will be consolidated into a single ProCo that day. Commission approval of the ProCo consolidation is not required because DEC ProCo and DEP ProCo are not public utilities under FPA section 201. Applicants nonetheless include this update out of an abundance of caution and confirm that they will submit proposed revisions to the Joint OATT under FPA section 205 to reflect the consolidation of DEC ProCo and DEP ProCo into a single ProCo.

<sup>7</sup> In addition to the instant application, the Internal Reorganization also requires approval by the NCUC and PSCSC. Neither the Internal Reorganization nor the relief sought in this application will foreclose, preempt, or otherwise limit the authority of the NCUC and PSCSC to review the applications pending before them and take any action on them consistent with state law and jurisdiction. The Companies are also serving copies of the instant application on the NCUC, the Public Staff–NCUC, PSCSC, and the South Carolina Office of Regulatory Staff.

three jurisdictions in order to consummate the Internal Reorganization on January 1, 2027 (“Legal Day 1”).<sup>8</sup>

## **I. EXECUTIVE SUMMARY**

The purpose of the Internal Reorganization is to consolidate DEC and DEP into a single electric utility—that single utility will be DEC, as the survivor of the merger, but referred to herein as “Carolinas 1U” to avoid confusion with DEC as it currently exists)—serving existing wholesale and retail customers in the legacy DEC and DEP service territories in North Carolina and South Carolina. The Internal Reorganization will allow Carolinas 1U to unlock substantial savings to customers on a system basis through planning, execution, and operational efficiencies. Specifically, the Internal Reorganization will allow Carolinas 1U to: plan investments in necessary generation and transmission resources more efficiently; execute those plans more efficiently by siting and building those resources more cost-effectively; and operate those resources more efficiently as a fully integrated system.

The single utility’s ability to plan, execute, and operate resources more efficiently will result in substantial cost savings, benefiting customers by reducing the overall costs to serve. The vast majority of the quantifiable customer savings identified by the Applicants come from these planning, execution, and operational efficiencies. The remainder of the benefits is derived from corporate administrative savings. After factoring in the cost to achieve these savings, the Applicants project that the Internal Reorganization will save customers more than \$1 billion over the course of twelve years.

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<sup>8</sup> If the Internal Reorganization is approved, Applicants will make a series of implementation filings pursuant to FPA section 205.

As further described below and in the testimony supporting this application, the Internal Reorganization is consistent with the public interest. As is the case with most internal reorganizations, there will be no adverse impact on rates, competition, or regulation, and there will be no inappropriate cross-subsidization. However, a natural consequence of combining two utilities with different cost structures (one higher and one lower) is a reallocation of the costs of the legacy systems among the different jurisdictions served by the utilities. That is in fact what will happen in this case—the Internal Reorganization will result in a reallocation of costs from the wholesale to retail jurisdictions, with South Carolina retail being most significantly affected, and, to a lesser extent, North Carolina retail and existing DEC wholesale power supply customers.

Specifically, the Companies' wholesale jurisdiction represents a larger share of the DEP system (the higher-cost system) than the DEC system, while the South Carolina retail jurisdiction currently represents a larger share of the DEC system (the lower-cost system). The Internal Reorganization will result in legacy system costs being reallocated from existing DEP wholesale power supply customers to the retail jurisdictions and existing DEC wholesale power supply customers. The Internal Reorganization will result in a similar rate adjustment effect between the Joint OATT transmission customers of the legacy Companies, as DEP's Joint OATT rates are generally higher than DEC's Joint OATT rates, and a combined formula rate will thus result in a lower rate for legacy DEP Joint OATT customers and a higher rate for legacy DEC Joint OATT customers.

To address these short-term impacts, the Companies are proposing and seek Commission approval of a rate mitigation plan (the "1U Rate Mitigation Plan"). The 1U Rate Mitigation Plan acts as a bridge to address these cost reallocation challenges between the jurisdictions and among the wholesale customer classes. The 1U Rate Mitigation Plan consists of two components: (1) the

“Share the Benefits Plan;” and (2) the “OATT Mitigation Plan.” The Share the Benefits Plan involves legacy DEP wholesale power supply customers deferring their merger savings for a period of five years to provide revenue to fund credits to the Companies’ South Carolina retail customers and existing DEC wholesale power supply customers to offset cost reallocations resulting from the Internal Reorganization. The OATT Mitigation Plan, in turn, involves three rate mitigation measures to address transmission cost reallocations resulting from the Internal Reorganization.

The 1U Rate Mitigation Plan is uniquely tailored to address the particular short-term impacts that result from the Internal Reorganization, which is driven by the potential to achieve long-run customer savings. The Commission has long held that the existence of a rate increase as a result of a particular transaction does not necessarily mean that there is an “adverse impact” on rates under section 203 of the FPA.<sup>9</sup> The type of cost equalization effects observed here are not uncommon when two vertically-integrated utilities merge, and the Commission has accepted effective mitigation proposals to address the near-term impacts.<sup>10</sup> The broad-based agreement amongst most of the Companies’ legacy wholesale power supply customers is evidence that the 1U Rate Mitigation Plan is consistent with the public interest.

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<sup>9</sup> See, e.g., *Entergy Servs., LLC*, 168 FERC ¶ 61,207 at P 49 (2019) (“Based on Applicants’ representations, we find that, while the Proposed Transaction will increase rates, in the unique circumstances of this case, such an increase is not adverse.”), *order on reh’g and clarification*, 171 FERC ¶ 61,038 (2020); *ITC Holdings Corp.*, 143 FERC ¶ 61,256 at P 119 (2013) (“[W]e find, based on the evidence in the record, that Applicants have demonstrated that the Proposed Transaction will not have an adverse effect on rates. Although rates will increase for some customers as a result of this transaction, Applicants have shown that the Proposed Transaction will result in offsetting benefits.”), *order dismissing reh’g and clarification*, 151 FERC ¶ 61,266 (2015).

<sup>10</sup> See, e.g., *NextEra Energy, Inc.*, 173 FERC ¶ 61,029 at P 27 (2020) (approving internal reorganization that proposed mitigation measures to address potential rate impacts on the grounds that the commitments were “sufficient to mitigate any potential adverse effect on rates resulting from the [transaction]”).

For all of these reasons, Applicants respectfully request that the Commission act on this application at the earliest possible date within the Commission’s 180-day review period and approve the proposed Internal Reorganization as consistent with the public interest.

## **II. BACKGROUND**

### **A. Description of Applicants**

#### **1. Duke Energy Corporation**

Duke Energy is a Fortune 150 energy holding company headquartered in Charlotte, North Carolina.<sup>11</sup> Through its franchised utility affiliates—DEC, DEP, Duke Energy Florida, LLC (“DEF”), DEI, Duke Energy Kentucky, Inc., and Duke Energy Ohio, Inc.—Duke Energy serves approximately 8.6 million retail and wholesale customers in North Carolina, South Carolina, Florida, Indiana, Ohio, and Kentucky. Duke Energy collectively owns more than 55,100 megawatts (“MW”) of energy capacity, and its natural gas utilities serve 1.7 million customers in North Carolina, South Carolina, Tennessee, Kentucky, and Ohio. Additionally, Piedmont Natural Gas Company, Inc. (“Piedmont”), a wholly-owned direct subsidiary of Duke Energy, is engaged in the business of transporting, distributing, and selling natural gas in the states of North Carolina, South Carolina, and Tennessee.<sup>12</sup>

#### **2. Duke Energy Carolinas, LLC**

DEC is a wholly-owned direct subsidiary of Duke Energy. DEC is a vertically integrated public utility providing generation, transmission, and distribution services to approximately 2.9

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<sup>11</sup> To the best of Duke Energy’s knowledge, only one entity holds ten percent or more of Duke Energy’s outstanding common stock, and is therefore considered an affiliate, pursuant to its authority to hold up to twenty percent of the voting securities of any public utility. *See* Quarterly Report of the Vanguard Group, Inc., Docket No. EC19-57-002 (filed Aug. 6, 2024) (noting a 10.85 percent ownership in Duke Energy).

<sup>12</sup> On July 29, 2025, Duke Energy announced the sale of Piedmont’s Tennessee assets to Spire Inc. After the sale—which is expected to close in the first quarter of 2026—Piedmont will transport, distribute, and sell natural gas only in North Carolina and South Carolina.

million retail customers over an approximately 24,000 square mile service area in Central and Western North Carolina and Western South Carolina. DEC's service area includes sixty-two counties—forty-four in North Carolina and eighteen in South Carolina.

DEC provides transmission service under a formula rate in the Joint OATT.<sup>13</sup> DEC provides wholesale power supply service to several load-serving entities in the Carolinas pursuant to long-term contracts on file with the Commission.

In addition to being regulated by FERC, DEC is also regulated by the NCUC and the PSCSC.

DEC is registered with the North American Electric Reliability Corporation (“NERC”) as a Balancing Authority (“BA”) for the DUK Balancing Authority Area (“BAA”).

### **3. Duke Energy Progress, LLC**

DEP is a wholly-owned direct subsidiary of Progress Energy, Inc. (“Progress”), which, in turn, is a wholly-owned subsidiary of Duke Energy. DEP is a vertically integrated public utility providing generation, transmission, and distribution services to approximately 1.6 million retail customers over an approximately 28,000 square mile service area covering a substantial portion of the coastal plain of North Carolina extending from the Piedmont to the Atlantic coast, the lower Piedmont section of North Carolina, an area in Western North Carolina in and around the city of Asheville, and an area in the Northeastern portion of South Carolina.

DEP provides transmission service under a formula rate in the Joint OATT. DEP provides wholesale power supply service to several load-serving entities in the Carolinas pursuant to long-term contracts on file with the Commission.

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<sup>13</sup> The Joint OATT governs the provision of transmission service across the facilities owned by DEC, DEP, and DEF. *See* Duke Energy Carolinas, LLC – Tariffs, Rate Schedules and Service Agreements, Tariff Volume No. 4, Open Access Transmission Tariff (18.0.0).

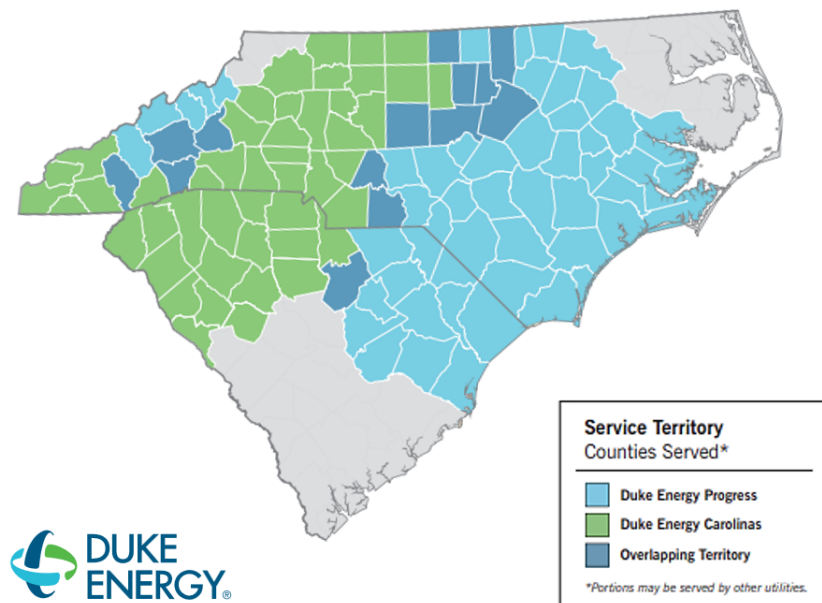
In addition to being regulated by FERC, DEC is also regulated by the NCUC and the PSCSC.

DEP is registered with NERC as a BA for the CPLW and CPLE BAAs.

#### 4. The Current BAA/Service Territory Configuration

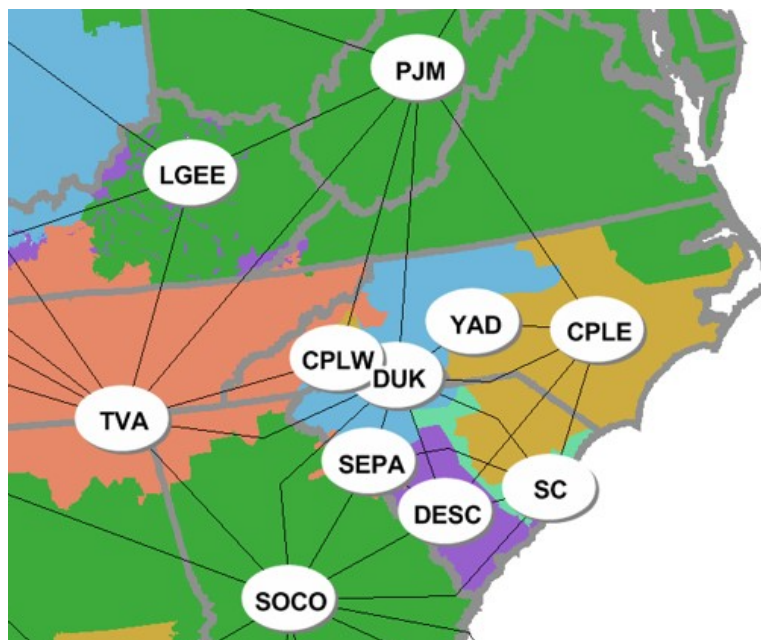
As shown in the territory map below, DEC’s current service territory covers the western parts of the Carolinas, including portions of the Blue Ridge Mountains and foothills, and the heavily populated Piedmont region east of the mountains. In contrast, DEP’s current service territory mostly covers the eastern parts of the Carolinas toward the coast, with a relatively small pocket of territory in Western North Carolina along the Tennessee border and around Asheville.

### Carolinas Service Territory



Accordingly, DEC’s service territory is, in general, hillier and more wooded, whereas DEP’s service territory, apart from the Western North Carolina region, is generally more coastal and flat, with fewer wooded areas and less cloud cover.

Additionally, the graphic below depicts the Companies' three current BAAs: DUK, CPLE, and CPLW. The Companies are working with NERC and the SERC Reliability Corporation to consolidate the BAAs contemporaneously with the Internal Reorganization.



***B. The 2012 Duke/Progress Holding Company Merger***

In 2011, Duke Energy and Progress, together with their public utility subsidiaries—DEC (a subsidiary of Duke Energy) and Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (“CPL”) (then a subsidiary of Progress)—requested Commission authorization for a merger pursuant to which Progress would become a wholly-owned subsidiary of Duke Energy (“Duke/Progress Merger”).<sup>14</sup> Although Duke Energy and Progress (through their public utility subsidiaries) each owned a large amount of generation capacity, the DEC and CPL BAAs in North Carolina and South Carolina were the only markets in which the supply capabilities of DEC and

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<sup>14</sup> Application for Authorization of Disposition of Jurisdictional Assets and Merger under Sections 203(a)(1) and 203(a)(2) of the Federal Power Act, Docket No. EC11-60-000 (filed Apr. 4, 2011) (“Duke/Progress Merger Application”).

CPL overlapped. Specifically, DEC served wholesale and retail customers in the DUK BAA (including areas in both North Carolina and South Carolina), and CPL served wholesale and retail customers in the CPLE and CPLW BAAs (also including areas in both North Carolina and South Carolina).<sup>15</sup> Thus, for purposes of demonstrating that the Duke/Progress Merger was consistent with the public interest, the analysis of potential horizontal market power concerns focused on three BAAs: DUK, CPLE, and CPLW.<sup>16</sup>

The Commission initially concluded that the proposed Duke/Progress Merger resulted in certain screen failures that raised concerns regarding adverse effects on competition in the DUK and CPLE BAAs.<sup>17</sup> Therefore, the Commission made approval of the Duke/Progress Merger conditional on the adoption of certain market mitigation measures.<sup>18</sup> In 2012, the Commission accepted Duke Energy and Progress' compliance filing<sup>19</sup> that proposed: (1) "Permanent Mitigation" in the form of transmission upgrades; (2) "Interim Mitigation" in the form of firm sales of capacity and energy until the new transmission projects constituting the proposed Permanent Mitigation were placed in service; and (3) certain "Stub Mitigation" in the form of a limited set-aside of transmission capacity on the internal interface path from the DEC BAA to the

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<sup>15</sup> In the Duke/Progress Merger proceeding, the CPL BAAs were referred to as Progress Energy Carolinas-East, or PEC-East, and Progress Energy Carolinas-West, or PEC-West. To avoid confusion, in this application, we refer to the BAAs as they are now referenced, including when discussing the Duke/Progress Merger proceeding (i.e., when the parties were using the references PEC-East and PEC-West).

<sup>16</sup> Duke/Progress Merger Application at 18.

<sup>17</sup> *Duke Energy Corp.*, 136 FERC ¶ 61,245 at PP 1, 117 (2011) ("September 2011 Merger Order"), *reh'g denied*, 149 FERC ¶ 61,078 (2014) ("October 14 Rehearing Order").

<sup>18</sup> *Id.*

<sup>19</sup> Revised Compliance Filing, Docket No. EC11-60-004 (filed Mar. 26, 2012) ("2012 Compliance Filing").

CPLE BAA, for the summer off-peak season/load period, to be monitored by Potomac Economics Ltd. (“Potomac Economics”).<sup>20</sup>

In 2014, the Commission permitted Duke Energy and Progress to supplement their 2012 Compliance Filing, and denied rehearing of, *inter alia*, the September 2011 Merger Order and the June 2012 Merger Order.<sup>21</sup> As a result of the October 2014 Rehearing Order, the Stub Mitigation ultimately accepted by the Commission consisted of: (1) DEC establishing a transmission set-aside of 129 MW of firm transmission capacity on the internal interface between the DEC BAA to the CPLE BAA in the summer off-peak season/load period; (2) DEC operating certain Phase Shifters (“PARs”) to eliminate overloads and increase available transmission capability (“ATC”) into the CPLE BAA; and (3) independent monitoring of the transmission set-aside requirement and the PARs operation by Potomac Economics, with annual reporting in the Duke/Progress Merger docket.<sup>22</sup>

Since 2014, Potomac Economics has filed annual reports in Docket No. EC11-60 to address the Companies’ compliance with the Stub Mitigation commitments. Each year, one report addresses the set-aside requirement,<sup>23</sup> and a separate report addresses operation of the PARs within

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<sup>20</sup> *Duke Energy Corp.*, 139 FERC ¶ 61,194 (2012) (“June 2012 Merger Order”) (accepting the 2012 Compliance Filing). To date, all of the Permanent Mitigation and the Interim Mitigation has been completed. As confirmed by the annual Potomac Economics reports filed in the Duke/Progress Merger docket (Docket No. EC11-60-000), DEC has continued to meet the Stub Mitigation commitments since the Duke/Progress Merger.

<sup>21</sup> October 2014 Rehearing Order, 149 FERC ¶ 61,078.

<sup>22</sup> *Id.* at PP 76-77, 79.

<sup>23</sup> As Potomac Economics has explained, the Companies’ protocols for implementing the 129 MW set-aside have evolved over the years. For the summers of 2014 through 2016, the Companies committed to making no short-term firm reservations during summer off-peak hours. Seasonal Independent Monitoring Report on “Stub Mitigation” Transmission Set-Aside for Duke Energy Corp. and Progress Energy, Inc., Docket No. EC11-60-004, at 3-4 (filed Sept. 30, 2024) (“2024 Set-Aside Report”). Beginning in 2017, the Companies implemented an automated solution that allows the Companies to reserve short-term firm ATC on the DUK to CPLE interface provided that 129 MW of ATC remains set-aside for non-affiliates. *Id.* at 3. For long-term firm transmission requests, when the Companies or an affiliate make a service request on the DUK to CPLE interface, “the ATC will be reduced by 129 MW before assessing the request,” although “the 129 MW may be lower if new third-party firm requests on the interface are in queue or confirmed.” *Id.* at 4.

CPLE.<sup>24</sup> In these annual reports, Potomac Economics has consistently concluded that the Companies complied with the Stub Mitigation obligations.

### III. PURPOSE AND DRIVERS OF THE INTERNAL REORGANIZATION

Since the Duke/Progress Merger, the Companies have taken significant steps to achieve operational efficiencies under separate operating companies, including aligning customer service systems, corporate support functions, and regulatory processes where possible. Through these efforts, the Companies have achieved over \$1 billion in customer savings. In particular, through operation of the Joint Dispatch Agreement (“JDA”)—approved by the Commission in connection with the Duke/Progress Merger<sup>25</sup>—the Companies have achieved hundreds of millions of dollars in customer savings by jointly dispatching generation resources that remain independently owned by either DEC or DEP and sharing in the resulting production cost savings.

Despite these benefits, DEC and DEP fundamentally remain two *separate* operating utilities, and existing regulatory constraints prohibit DEC and DEP from functioning as one utility. For example, the JDA does not permit the Companies to jointly plan to meet their combined capacity needs, requiring each utility to separately ensure that it has adequate resources to

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<sup>24</sup> In accordance with the October 2014 Rehearing Order, Potomac Economics (1) monitors “the Company’s ATC process to ensure the ATC values reflect the fact that the PARs should be operated to increase ATC on the DEC-to-DEP-East transmission path” and (2) “report[s] on statistics relating to the operation of the PARs as specified by the Commission in its [October] 2014 order.” Seasonal Independent Monitoring Report on “Stub Mitigation” PAR Operations for Duke Energy Corp. and Progress Energy, Inc., Docket No. EC11-60-004, at 4 (filed Oct. 8, 2024) (“2024 PAR Report”). In terms of meeting Stub Mitigation requirements, Potomac Economics has explained that “the most important aspect of the PARs being in service is that their availability increases the ATC, as opposed to actual operating benefits,” meaning that “ensuring that *potential* operation of the PARs in the operating horizon is reflected in ATC values is the most important issue for the PAR monitoring.” *Id.* at 6 (emphasis in original). Over the years, every PARs report from Potomac Economics has concluded that there were “[no] instances in the operating horizon that require[d] operation of the PARs,” “there were no curtailments of firm schedules on the DEC-to-DEP-East path,” and the “operation of the PARs did not raise concerns” for the relevant reporting period. *Id.* at 9.

<sup>25</sup> See *Duke Energy Corp.*, 139 FERC ¶ 61,193 (2012), *reh’g denied*, 151 FERC ¶ 61,242 (2015), *vacated in part sub nom. Orangeburg S.C. v. FERC*, 862 F.3d 1071 (D.C. Cir. 2017). Pursuant to the JDA, DEC and DEP jointly dispatch their generation fleets to operate their systems more economically for the benefit of their customers.

independently meet anticipated demand—even where sharing resources would produce better outcomes for customers. Additionally, as explained above, the Companies are responsible for three separate BAAs—DUK, CPLW, and CPLE—and, as a result, must maintain their own real-time load and generation balance and independently satisfy NERC Reliability Standards.

The merger of DEC and DEP into Carolinas 1U overcomes these limitations by enabling full integration of resource planning and operations across a single, combined utility. The efficiencies gained through this integration will deliver customer savings over and above those already achieved under the existing framework. Specifically, the Internal Reorganization will achieve lower overall costs for customers by allowing Carolinas 1U to:

- **Plan** investments in necessary generation and transmission resources more efficiently;
- **Execute** those plans more efficiently by siting and building those resources more cost-effectively; and
- **Operate** those resources more efficiently as a fully integrated system.

Although the amount of actual savings will depend on events as they unfold over time, the system savings are estimated to be in the *billions*—anywhere from \$1.6 billion to approximately \$3.2 billion.<sup>26</sup> As such, the benefits of the Internal Reorganization will far exceed the costs of the Internal Reorganization under any reasonably foreseeable resource planning scenario. These quantifiable benefits flow almost entirely from the planning, execution, and operational

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<sup>26</sup> See Attachment 1, Prepared Direct Testimony of Nelson Peeler, Jr. at 3, 17. As discussed above, it is well established under the Commission’s FPA section 203 jurisprudence that merging parties are not required to demonstrate affirmative customer benefits. See *UtiliCorp United Inc.*, 38 FERC ¶ 61,291, at 61,957 n.5 (1987) (“Section 203(a) does not require a showing of a ‘positive benefit’ to the public in order for a merger to be found to be in the public interest. Only an absence of a negative detriment is required.”) (internal quotations omitted). Nonetheless, the magnitude of potential customer savings is important context for understanding the significant beneficial impacts of the Internal Reorganization.

efficiencies Carolinas 1U can achieve by removing the constraints that currently do not allow DEC and DEP to fully integrate their system planning and operations, all as described in witness Nelson Peeler, Jr.'s testimony.

With respect to *planning* efficiencies, having a single reserve margin to plan towards (the Carolinas 1U scenario) versus having to separately plan to meet separate reserve margins (the current scenario) will allow the single, combined utility to defer construction and delay in-service dates of generation and transmission resources that otherwise would have been needed earlier if the Companies were required to operate as separate utilities. Specifically, because DEC's and DEP's respective system peaks are not perfectly correlated, planning to a combined system peak results in load diversity and a lower overall peak relative to simply adding the system peaks of legacy DEC and legacy DEP together. These diversity benefits will allow Carolinas 1U to defer certain capital investments that otherwise would have to be built by DEC and/or DEP, operating alone, to meet the increased planning reserve margin independently.

Carolinas 1U will also be able to *execute* its resource planning more efficiently. For example, building utility-scale solar generation requires expanses of flat, open land and is better suited to DEP's current service territory, whereas pumped storage hydro resources are more suited to DEC's service territory due to its mountainous terrain. As such, by eliminating geographic barriers that otherwise would exist without the Internal Reorganization, Carolinas 1U will be able to capitalize on the geographic diversity of the legacy DEC and legacy DEP service territories in making resource plans. In addition, existing natural gas pipelines run through Western North Carolina in DEC's current service territory, making it more cost effective to site and develop natural gas generation resources in that territory. Without the Internal Reorganization, the cost of siting additional natural gas plants in DEP's service territory would generally be higher because

of the need to build additional pipeline infrastructure to support any future additional plants. Further, Carolinas 1U will be a financially stronger utility than either DEC or DEP alone, and that financial strength will significantly enhance the single utility's ability to finance large generation and transmission investments needed to support and reliably serve growing demand. Enhanced financial strength will also better position Carolinas 1U to manage unexpected events, such as severe weather or fuel price volatility, without compromising service or financial stability. Lastly, a single, combined utility creates a broader customer base over which these investments can be spread, helping to moderate customer rate impacts over time.

The Internal Reorganization will also allow Carolinas 1U to *operate* more efficiently. Specifically, the Internal Reorganization will consolidate the three existing DEC and DEP BAAs (DUK, CPLE, and CPLW) into a single BAA, thereby allowing Carolinas 1U to jointly commit resources. Under the JDA, DEC and DEP may not commit their generation resources to assist with each other's operational needs—they may only dispatch resources that are already operating. The ability to engage in joint unit commitment means that, post-Internal Reorganization, Carolinas 1U will only need to meet a *single* operating reserve requirement versus the situation today, where DEC and DEP must meet *separate* operating reserve requirements. From these operational efficiencies, customers will realize savings through reduced fuel usage, reduced unit cycling, reduced reliability purchases, and reduced solar curtailment.

In sum, the entire purpose of the Internal Reorganization is to allow the full integration of DEC and DEP into a single operating utility and for customers to reap the full measure of the benefits of that integration. Notably, the efficiencies to be achieved through the Internal Reorganization come at a significant juncture in the industry. As the industry works toward meeting transitional challenges in the coming years—including projected increases in load, the

integration of new generation technology and storage facilities, and the need to ensure grid reliability—the Internal Reorganization will position the Companies to better serve the region’s growing economy by more effectively managing energy needs across the Carolinas.

#### **IV. DESCRIPTION OF THE INTERNAL REORGANIZATION**

The Internal Reorganization is structured as an internal corporate reorganization, as both DEC and DEP are subsidiaries of Duke Energy. Pursuant to an Agreement and Plan of Merger (“Merger Agreement”),<sup>27</sup> the Internal Reorganization will be accomplished in two steps: (1) Duke Energy will contribute DEC to Progress; and (2) DEP will merge into DEC. At the Internal Reorganization’s closing, DEC will survive the merger, and DEP will cease to exist as an entity. These steps are shown in the pre- and post-closing organizational charts included herein as Exhibit C. Subject to timely receipt of all required approvals, DEC and DEP anticipate closing the Internal Reorganization on January 1, 2027. Applicants will inform the Commission of the actual closing date in a notice of consummation to be filed in the instant docket.

#### **V. THE INTERNAL REORGANIZATION IS CONSISTENT WITH THE PUBLIC INTEREST**

Section 203 of the FPA provides that the Commission shall authorize a proposed transaction if it determines that the transaction “will be consistent with the public interest, and will not result in inappropriate cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company.”<sup>28</sup> In determining whether a proposed transaction is consistent with the public interest, the Commission considers three

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<sup>27</sup> A form of the Merger Agreement, which will be substantively the same as the final version that will be executed to consummate the Internal Reorganization, is attached hereto as Exhibit I.

<sup>28</sup> 16 U.S.C. § 824a(a)(4).

factors: (1) the effect on rates; (2) the effect on competition; and (3) the effect on regulation.<sup>29</sup> Applicants need not show that a transaction positively benefits the public interest, but rather simply that it is “consistent with the public interest,” i.e., that the transaction does not harm the public interest.<sup>30</sup>

As demonstrated below, the Internal Reorganization satisfies all of these standards and therefore should be approved.

**A. *The Internal Reorganization Will Not Have an Adverse Effect on Rates***

The Internal Reorganization will not have an adverse impact on Commission-jurisdictional rates. The Companies currently operate separate retail service territories, have their own wholesale power supply contracts, and have separate formula rate templates and zonal revenue requirements under the Joint OATT.<sup>31</sup> The Companies’ Joint OATT rates are generally based on historical (rather than projected) costs and are subject to update on June 1 of each year.

After the Internal Reorganization, Carolinas 1U will operate under a single set of books and a single FERC Form 1. For purposes of Commission-jurisdictional transmission rates, Carolinas 1U will also have a single OATT formula rate template and revenue requirement. With respect to Commission-jurisdictional wholesale power supply rates, Carolinas 1U will serve wholesale power supply customers under contract with the Companies today.

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<sup>29</sup> See *Revised Filing Requirements Under Part 33 of the Comm’n’s Reguls.*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,872-73 (2000), *order on reh’g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001).

<sup>30</sup> See, e.g., *Tex.-N.M. Power Co.*, 105 FERC ¶ 61,028 at PP 23, 23 n.14 (2003) (“*Tex.-N.M. Power*”) (citing *Pac. Power & Light Co. v. FPC*, 111 F.2d 1014, 1016-17 (9th Cir. 1940)).

<sup>31</sup> Rates for transmission service provided by DEC under the Joint OATT are determined pursuant to the formula rate contained in Schedule 10-B, Exhibit B of the Joint OATT, with DEC’s annual transmission revenue requirement derived each year by inputting DEC’s FERC Form 1 information. Rates for transmission service provided by DEP under the Joint OATT are determined pursuant to the formula rate contained in Attachment H.1 of the Joint OATT. DEP’s formula rate uses a historical test year methodology whereby DEP’s rates change each June 1 based on the immediately preceding year’s cost of service, calculated using end-of-year balances from FERC Form No. 1.

As previewed above, merging DEC and DEP will create a single utility that calculates rates for wholesale power supply service and transmission service. The numerator of these rates will be based on the combined cost of service of the newly merged utility (i.e., it will include the costs of legacy DEC and legacy DEP). Similarly, the denominator of these rates will be the combined demand of the customers of both legacy DEC and DEP. As is necessarily the case when two such rate structures are combined, the resulting merged rate will reflect some degree of equalization (or averaging) such that the merged rate is comparatively lower for customers of the higher-cost legacy system (here, DEP) and comparatively higher for customers of the lower-cost legacy system (here, DEC). As explained in the testimonies of witnesses Jennifer Ellis and Blain Atkins, this “Equalization Effect” applies to both wholesale power supply rates and transmission service rates.

In addition to the Equalization Effect within the context of the Companies’ FERC-jurisdictional rates, the Internal Reorganization will result in a cost reallocation amongst the Companies’ retail jurisdictions. The cost reallocation impacting the retail jurisdictions is purely a result of the same Equalization Effect in the context of merged retail cost of service calculations.

However, notwithstanding the cost reallocations resulting from the Internal Reorganization, the business case and long-run customer benefit justification for consolidating DEP into DEC and operating as a combined utility are very strong, and, as explained below, the Companies have fashioned a creative solution to address the short-term impacts of the Internal Reorganization.

### **1. Summary of Customer Engagement on the 1U Rate Mitigation Plan**

The Companies have been engaged in extensive customer outreach regarding the Internal Reorganization for well over a year and have developed the 1U Rate Mitigation Plan to mitigate short-term impacts of the Internal Reorganization. Because the 1U Rate Mitigation Plan does not follow a specific blueprint, the Companies worked closely with their current transmission and

wholesale power supply customers to communicate the value and impact of the Internal Reorganization and to craft the 1U Rate Mitigation Plan. The Companies held roughly a dozen formal meetings with their entire OATT customer class to develop the OATT Mitigation Plan. Additionally, the Companies held countless one-on-one meetings with their current wholesale power supply customers to explain the Share the Benefits Plan. The 1U Rate Mitigation Plan is the result of extensive customer feedback and input from these outreach efforts.

## **2. Overview of the 1U Rate Mitigation Plan**

The Internal Reorganization is designed to achieve customer benefits over the long term through reduced system cost of service largely resulting from the planning, execution, and operational efficiencies explained above and described in greater detail in the testimony of witness Peeler. However, an additional natural consequence of the Internal Reorganization is a reallocation of costs among the three jurisdictions.

As indicated above, these cost reallocation impacts are a function of differences in the system costs of legacy DEC and DEP and the varying jurisdictional shares of each system. Today, DEP's cost of service per MW-hour is higher than DEC's. Additionally, the wholesale jurisdiction currently represents a larger share of the DEP system (the higher-cost system) than the DEC system, and the South Carolina retail jurisdiction currently represents a larger share of the DEC system (the lower-cost system). Post-Internal Reorganization, under the single cost of service study reflecting Carolinas 1U, there will necessarily be changes in the outcomes at the jurisdictional level resulting from the cost of service allocation of the combined system. This result flows naturally from the fact that, as noted above: (1) the costs of the Companies' existing systems are not identical; and (2) the current jurisdictional allocations of the Companies' existing systems are not identical.

The impacts of this cost reallocation effect on the Companies' current wholesale power supply customers are described in witness Ellis' testimony, and the impacts to the Companies' current Joint OATT customers are described in witness Atkins' testimony. In short, all else being equal, as formula rates are re-calculated for a merged company, DEP's existing wholesale power supply customers would see lower rates right away, and DEC's existing wholesale power supply customers would see higher rates, as the unified rate design allocates costs differently than today. Further, additional costs would be allocated to the Companies' South Carolina retail jurisdiction as compared to today. This occurs because the Companies' South Carolina retail jurisdiction will be receiving a larger allocation of the higher-cost system (DEP) than was the case before the Internal Reorganization.

To mitigate cost reallocation impacts in the near term, the Companies are proposing the 1U Rate Mitigation Plan—a five-year mitigation plan designed to address the impact of cost reallocation in the short term. The 1U Rate Mitigation Plan consists of two components: the “Share the Benefits Plan” and the “OATT Mitigation Plan.” The Share the Benefits Plan, as the name implies, shares the benefits of the Internal Reorganization among the jurisdictions in the near term. Thus, this targeted plan overcomes cost reallocation challenges in the near term for both the Companies' South Carolina retail jurisdiction and DEC's existing wholesale power supply customers and acts as a temporary bridge to facilitate full regulatory approval of the Internal Reorganization. Similarly, the OATT Mitigation Plan mitigates concerns regarding potential transmission rate increases following the Internal Reorganization by providing two separate credits to legacy DEC Joint OATT customers for five years and implementing a “lower of” methodology for calculating ancillary services rates.

On balance, the 1U Rate Mitigation Plan is a carefully constructed and negotiated solution that balances the interests of all affected jurisdictions and wholesale customer classes and positions all existing customers of DEC and DEP to benefit in the long run from the Internal Reorganization. It is also consistent with the Commission’s history of approving transitional rate protections.<sup>32</sup>

**a. Share the Benefits Plan**

At a high level, as explained by witness Ellis, the Share the Benefits Plan smooths the transition to Carolinas 1U by mitigating the cost reallocation impacts described above in the short term. On Legal Day One—the day the Internal Reorganization is effectuated (and DEC and DEP become one utility)—Carolinas 1U will have one set of books, and, ultimately, a single FERC Form 1, and each wholesale power supply customer of legacy DEC and legacy DEP will take service under formula rate templates that are populated with a single set of cost impacts. Consequently, without an intervening mitigation plan, the impacts described above will occur.

The primary objectives of the Share the Benefits Plan are to address the impacts to the Companies’ South Carolina retail jurisdiction, as it is allocated a greater proportional responsibility for system costs, and to protect DEC’s existing wholesale power supply customers from an immediate rate increase related to cost sharing of the DEP system (the higher-cost system).

To mitigate the near-term impacts of the cost reallocation associated with the Internal Reorganization, the Companies are proposing that existing DEP wholesale power supply customers temporarily defer some of the immediate cost reallocation benefits they would otherwise receive and that they pay a fixed monthly “adder” for a five-year period. In essence, the Share the Benefits Plan asks existing DEP wholesale power supply customers to continue paying

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<sup>32</sup> *NextEra Energy, Inc.*, 173 FERC ¶ 61,029 at PP 21, 27 (2020) (finding proposed five-year mitigation plan “sufficient to mitigate any potential adverse effect on rates resulting from the Proposed Transaction”).

charges based on today's allocation, rather than paying charges based on a one utility scenario, for a five-year transitional period. This transitional "adder" maintains the costs existing DEP wholesale power supply customers would otherwise have paid based on the legacy DEP system absent the Internal Reorganization. In addition to this contribution, the Companies' North Carolina retail customers would contribute approximately \$25 million per year to the Companies' South Carolina retail customers over a six-year period.

**i. Deferred Benefits for DEP's Existing Wholesale Power Supply Customers**

With respect to DEP's current wholesale power supply customers, this delay in benefits will be effectuated through amendments to DEP's existing wholesale power supply customers' contracts to secure from those customers a \$55 million per year contribution to fund the Share the Benefits Plan for five years (2027–2031), beginning on Legal Day 1. Witness Ellis explains in detail how the Companies calculated the total amount of potential savings to be deferred by DEP's legacy wholesale power supply customers by analyzing what the current DEP wholesale power supply customers would have paid under a one utility scenario, versus their actual payments as stand-alone legacy DEP customers, over a three-year lookback period. This analysis established the amount that the Companies could work from in developing a mitigation plan to address the near term impacts of the Internal Reorganization on (1) existing DEC wholesale power supply customers that would otherwise see immediate upward pressure on their rates, and (2) the cost reallocation to the Companies' South Carolina retail jurisdiction during the period in which it would otherwise be negatively impacted.

From this analysis, the Companies derived specific amounts that each existing DEP wholesale power supply customer would be asked to contribute to the Share the Benefits Plan to offset the impact of cost reallocations that would otherwise impact DEC's existing wholesale

power supply customers and the Companies' South Carolina retail jurisdiction. Witness Ellis' testimony contains the customer-by-customer detail on what specific amount is requested from each legacy DEP wholesale power supply customer. Importantly, these amounts will be fixed for the five-year transitional period; they are not formulaic amounts, nor are they subject to any sort of true-up (up or down) during the five-year period. Establishing fixed values was critical to giving DEP's existing customers certainty about the extent of their contributions.

## **ii. Allocation of Deferred Benefit Amounts**

As witness Ellis explains, the Companies calculated an annual amount for the five-year transition period that would mitigate the rate impacts of the Internal Reorganization for each legacy DEC wholesale power supply customer and worked with each existing DEC wholesale power supply customer to evaluate their historical cost shift impacts, as well as their forecasted impacts to derive a per-customer annual bill credit. The specific amounts being allocated to each existing DEC wholesale power supply customer are stated in witness Ellis' testimony. Like the savings deferred by DEP's current wholesale power supply customers, the credits to DEC's current wholesale power supply customers are fixed for the five-year transition period.

Each dollar of deferred savings contributed by DEP's current wholesale power supply customers that is not being used to fund a credit to DEC's current wholesale power supply customers will be used as a credit to the Companies' South Carolina retail customers. Specifically, due to the natural lag in retail rate cases, the contributions from the current DEP wholesale jurisdiction and current North Carolina retail jurisdiction will be deferred to a regulatory liability to begin flowing back to South Carolina retail customers of Carolinas 1U in the first South Carolina retail rate case after the Internal Reorganization.

The Share the Benefits Plan, while perhaps unorthodox, is necessary to achieve long-term customer benefits and is consistent with the Commission's long-held policy that utilities work collaboratively with their customers to address transaction-related rate issues. The Companies determined early on in their consideration of the Internal Reorganization that, in order to obtain state regulatory approvals, the Companies would need to develop such a rate mitigation plan. The Companies also worked closely with DEP's current wholesale power supply customers to explain that the Internal Reorganization could not be achieved without these customers agreeing to some form of deferred benefits. The Share the Benefits Plan is a delicate balancing of these various objectives and smooths the way for the long-run efficiencies that will accrue to all customers as a result of the Internal Reorganization.

Therefore, the Companies urge the Commission to find that the Share the Benefits Plan is consistent with the public interest and to expressly approve the Internal Reorganization on that basis.

**b. OATT Mitigation Plan**

The Companies developed a separate plan for addressing the short term impacts of the Internal Reorganization on transmission rates under the Companies' Joint OATT. As noted above, although DEC and DEP operate under a Joint OATT (along with DEF), they maintain separate revenue requirements and transmission rates for the DEC and DEP pricing zones. After the Internal Reorganization, Carolinas 1U will operate a single BAA and calculate a single transmission revenue requirement and set of transmission rates. Additionally, Carolinas 1U's OATT rates will continue to be updated on June 1 of each year. However, because Legal Day 1 is anticipated to be January 1, 2027, due to the timing of the Companies' Joint OATT rates, Carolinas 1U will not have a full year of FERC Form 1 data until after its first full year of merged operations—i.e., the FERC Form 1 compiled in early 2028 based on the 2027 calendar year.

Accordingly, the Companies’ plan to move to a single-system rate under the OATT for each relevant period, as reflected in Table 1 below:

Table 1

### 1U Transition Timeline

	2026		2027		2028	
	Jan-May	Jun-Dec	Jan-May	Jun-Dec	Jan-May	Jun-Dec
DEC	+ 2024 DEC FF1 + Estimated 2025 cap adds + 2024 DEC FF1 True-up	+ 2025 DEC FF1 + Estimated 2026 cap adds + 2025 DEC FF1 True-up		+ 2026 DEC FF1 + Estimated 2027 cap adds + 2026 DEC FF1 True-up		
DEP	+ 2024 DEP FF1 + No estimated 2025 cap adds + No True-up	+ 2025 DEP FF1 + No estimated 2026 cap adds + No True-up		+ 2026 DEP FF1 + No estimated 2027 cap adds + No True-up		
Combined						+ 2027 combined FF1 + No estimated 2028 cap adds + 2027 combined FF1 one-time annual true-up **

\* Horizontal red line represents legal day 1 (1/1/2027).

\*\* The “annual true-up” is a billing adjustment that compares the difference between the actual 2027 FF1 calendar year ATRR to the actual amount collected from legacy DEC and DEP customers for calendar year 2027. Subsequently, this billing adjustment would be calculated each year as part of the annual update process comparing that year’s actual ATRR to the prior calendar year’s amount collected from customers.

To be clear, the OATT Mitigation Plan is independent of the Share the Benefits Plan described above. The rate mitigation steps described in this section address potential cost shift impacts solely within the Companies’ Joint OATT customer class—i.e., between the legacy Joint OATT customers of DEC and DEP.

The OATT Mitigation Plan is explained in detail in witness Atkins’ testimony, but, to summarize here, the OATT Mitigation Plan consists of three parts: the “Equalization Adjustment,” the “Divisor Adjustment,” and the “Ancillary Services Adjustment.” At a high level, the OATT Mitigation Plan provides legacy DEC Joint OATT transmission customers with a credit over a

five-year period and adopts the lower rate between DEC and DEP when setting ancillary services rates.

#### **i. Transmission Service Rates**

As result of this Internal Reorganization, two primary drivers will impact transmission rates for legacy DEC Joint OATT customers.

First, as noted above, there is an Equalization Effect from the simple act of combining the legacy DEC and DEP Joint OATT rates. The Joint OATT rates for legacy DEC are generally lower than the Joint OATT rates for legacy DEP. As a result, merely merging DEC and DEP's current Joint OATT rates would lead to a near-term increase in the rates paid by legacy DEC transmission customers.

Second, there is a "Divisor Effect"—in other words, a drop in the load divisor—as a result of combining the legacy DUK, CPLW, and CPLE BAAs into one BAA and thereby eliminating point-to-point reservations between the three BAAs. As a result of maintaining separate BAAs, all current transmission customers, including DEC and DEP, are required to reserve point-to-point service in order to move power from one DEC/DEP BAA to load in another DEC/DEP BAA. These point-to-point reservations are *in addition* to the network service reserved for DEC and DEP native load and total roughly 34,000 MW-months annually, which is roughly ten percent of the combined total historical annual loads under the current DEC and DEP formula rates. In setting transmission rates today, these point-to-point reservations are included in the rate divisor with all other loads, and their presence *increases* the denominator, which in turn *lowers* the resulting Joint OATT rate for all Joint OATT customers. However, after the Internal Reorganization, a single BAA will "internalize" what was formerly the CPLE-DUK-CPLW interfaces and neither Carolinas 1U *nor any other transmission customer* will need to acquire point-to-point service to move power across the legacy DEC and DEP systems. As a result, legacy

point-to-point reservations will no longer appear in the rate calculation, and, all else being equal, this lone change will result in a roughly ten percent decrease in the Carolinas 1U OATT rate denominator, creating *upward* pressure on the Carolinas 1U OATT rates, as there are fewer MWs of demand in the denominator over which to spread the revenue requirement.

To mitigate these issues, the Companies are proposing the Equalization Adjustment and the Divisor Adjustment as part of the OATT Mitigation Plan. The Equalization Adjustment and the Divisor Adjustment will provide legacy DEC Joint OATT customers with deductions beginning on Legal Day 1 that will be gradually phased out over a five-year period. Specifically, as shown in Table 2 below, the Equalization Adjustment will lower legacy DEC Joint OATT customers’ revenue requirement for 2027-2031 for purposes of calculating rates. The Divisor Adjustment, in turn, will reinstate a fixed amount of MW into the Carolinas 1U OATT divisor to offset on a declining basis from 2027-2031. As shown in Table 3 below, the Companies will reinstate the 36,120 MW originally removed from the rate denominator at 100% on Legal Day 1 and then gradually decrease the MW amount by 20% each year, reaching 0% in year six.

Table 2

	<b>Year 1<sup>33</sup></b>	<b>Year 2</b>	<b>Year 3</b>	<b>Year 4</b>	<b>Year 5</b>
DEC Cost Shift Revenue Requirement Adj (\$000s)	(37,139)	(29,711)	(22,283)	(14,856)	(7,428)

Table 3

	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>	<b>Year 4</b>	<b>Year 5</b>
MW Divisor Adjustment	36,120	28,896	21,672	14,448	7,224

As noted above, the Equalization Adjustment and the Divisor Adjustment will phase out proportionately over a five-year period. Because all Carolinas 1U OATT customers will begin to

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<sup>33</sup> Year 1 in Tables 2 and 3 represents the 2028 OATT Annual Update.

see the benefits of coordinated planning, execution, and operations starting Legal Day 1, it is equitable to phase out the Equalization Adjustment as the benefits of the Internal Reorganization phase in.

The Equalization Adjustment and the Divisor Adjustment do not apply to legacy DEP Joint OATT customers because their rates will go down immediately as a result of the Internal Reorganization. In other words, because legacy DEP Joint OATT customers are part of a customer class that is an immediate beneficiary of the Internal Reorganization, further downward mitigation is not required.

## **ii. Ancillary Services Rates**

The OATT Mitigation Plan also addresses ancillary services rates under the Joint OATT. Unlike the Companies' transmission service rates, which update every year, both DEC and DEP have stated ancillary services rates which have not been updated for many years. Accordingly, when Carolinas 1U ultimately updates its ancillary services rates, the changes from the existing rates will likely be driven as much by the updating itself as any merger-related impact. Any merger-related impact would be driven by averaging the historical rate discrepancies between legacy DEC and legacy DEP, but in the context of updating inputs, a merger impact would be practically impossible to isolate without calculating two separate rate cases. Moreover, because some existing ancillary services rates are higher for legacy DEC customers and others are higher for legacy DEP customers, it is not clear that the Equalization Effect applies to ancillary services rates.

Consequently, pursuant to the OATT Mitigation Plan, the Companies are proposing the Ancillary Services Adjustment. Under the Ancillary Services Adjustment, the Companies will charge all Carolinas 1U OATT customers the *lower of* the existing DEC or DEP Joint OATT rate

for each ancillary service, as shown in Table 4, for a two-year period (calendar years 2027 and 2028) beginning on Legal Day 1.

Table 4

<b>Lower of DEC-DEP Ancillary Services Rates for Calendar Years 2027 and 2028</b>			
	<b>Current DEC Rate</b>	<b>Current DEP Rate</b>	<b>Lower of DEC-DEP Rate</b>
Schedule 1	\$ 55.00*	\$ 36.50	\$ 36.50
Schedule 3	\$ 38.00	\$ 47.52	\$ 38.00
Schedule 5	\$ 81.50	\$ 70.09	\$ 70.09
Schedule 6	\$ 81.50	\$ 50.09	\$ 50.09

\*DEC’s Schedule 1 rate is based on the 2024 annual update

Carolinas 1U will charge the lower of these rates for at least two years and up until such time as it has operational data as a merged company that could support a FPA section 205 filing to update the prevailing ancillary services rates across the board. As explained above, because Carolinas 1U will not have combined FERC Form 1 data until April 2028, Applicants commit that the earliest effective date that Carolinas 1U would seek to update ancillary services rates would be January 1, 2029—two years after Legal Day 1. This gives Carolinas 1U OATT customers two years of ancillary services rates that are either *status quo*, or *lower than the status quo*, after Legal Day 1. And, when Carolinas 1U ultimately files an ancillary services rate case, it will be subject to the Commission’s full review under FPA section 205 so that the rates resulting from such proceeding would have been found to be just and reasonable and not unduly discriminatory. For purposes of finding no adverse impact on Joint OATT rates, this two-year stay-out is more than sufficient mitigation for a number of reasons.

First, during the two-year moratorium, all Carolinas 1U OATT customers will get an affirmative benefit under the “lower of” approach because, by definition, they will be paying either the same ancillary services rate that they pay today, or a lower rate, depending on the specific ancillary service schedule. Second, when the ancillary services rates are eventually updated,

Carolinas 1U customers will get the benefit of a lower operating reserve requirement resulting from the combined utility, which, all else being equal, will lower rates compared to a two-utility scenario. Finally, there is no need for the Companies to separately address any Equalization Effect in ancillary services rates because, as noted above, the rates for these services are not consistently higher on either the DEC or DEP side, and, when ancillary services rates are finally updated, Carolinas 1U customers will get the aforementioned benefit of a lower reserve requirement that would not be possible without the Internal Reorganization.

### **3. Implementation of 1U Rate Mitigation Plan**

As explained above, the 1U Rate Mitigation Plan is the centerpiece of the Companies' plan to effectuate the Internal Reorganization and Applicants request that the Commission expressly approve the Internal Reorganization on that basis.

During the pendency of this proceeding, the Companies will work with each affected wholesale power supply customer to implement the terms of the Share the Benefits Plan in their respective wholesale power supply agreements, including the specific Reorganization Amounts designated for each customer as set forth in witness Ellis' testimony. Upon the Commission's approval of the Internal Reorganization, including the 1U Rate Mitigation Plan, the Companies will execute amended wholesale power supply agreements with their current wholesale power supply customers and will file them with the Commission under FPA section 205, to be effective as of the effective date of the Internal Reorganization.

Similarly, during the pendency of this proceeding, the Companies will be working with their current Joint OATT customers on a variety of FPA section 205 rate changes that will need to be made to the Joint OATT to facilitate the Internal Reorganization, including adoption of a single formula rate template, and the execution of any necessary updated service agreements. Those, too,

will be filed with the Commission under FPA section 205 after approval of the Internal Reorganization.

#### 4. Hold Harmless Commitment

In addition to the aforementioned mitigation measures that the Applicants are proposing to protect customers from the short-term cost reallocations, Applicants are also willing to make the traditional commitment to hold transmission and wholesale customers harmless from the transaction and transition costs associated with the Internal Reorganization in excess of transaction savings for a five-year period.<sup>34</sup> For that five-year period, the Companies will not include merger-related costs in their transmission revenue requirements or in their wholesale requirements rates, except to the extent they can demonstrate in a separate FPA section 205 proceeding that merger-related savings are equal to or in excess of the transaction-related costs included in the proposed rates. The Commission has approved this type of commitment in its *Merger Policy Statement*<sup>35</sup> and in subsequent orders,<sup>36</sup> and the scope of this commitment covers the types of costs the Commission has determined should be subject to hold harmless commitments.<sup>37</sup>

For all of these reasons, the Internal Reorganization will not have an adverse impact on rates.

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<sup>34</sup> See *Pol’y Statement on Hold Harmless Commitments*, 155 FERC ¶ 61,189 (2016) (“Hold Harmless Policy Statement”).

<sup>35</sup> *Merger Policy Statement*, FERC Stats. & Regs. ¶ 31,044 at 30,124.

<sup>36</sup> See, e.g., *Exelon Generation Co., LLC*, 176 FERC ¶ 61,121 at P 32 (2021); *El Paso Elec. Co.*, 170 FERC ¶ 61,280 at P 55 (2020), *order on reh’g*, 172 FERC ¶ 61,082 (2020); *NextEra Energy, Inc.*, 173 FERC ¶ 61,029 at P 29 (2020) (“NextEra”); *Tucson Elec. Power Co.*, 169 FERC ¶ 61,204 at P 40 (2020); *Dayton Power & Light Co.*, 160 FERC ¶ 61,034 at P 33 (2017); *Great Plains Energy Inc.*, 121 FERC ¶ 61,069 at P 48 & n.63 (2007) (citing cases), *reh’g denied*, 122 FERC ¶ 61,177 (2008); *Ameren Corp.*, 108 FERC ¶ 61,094 at P 68 (2004), *reh’g denied*, 111 FERC ¶ 61,055 (2005).

<sup>37</sup> Hold Harmless Policy Statement, 155 FERC ¶ 61,189 at PP 44-45.

***B. The Internal Reorganization Will Not Have an Adverse Effect on Competition***

The Commission's objective in analyzing the effect of a transaction on competition is to determine whether the transaction will result in higher prices or reduced output in electricity markets.<sup>38</sup> The Commission's *Merger Policy Statement* and Order No. 642 established both horizontal and vertical competitive analysis screens to allow the Commission to identify proposed mergers that are unlikely to present competitive concerns.<sup>39</sup> As demonstrated below, the Internal Reorganization raises no concerns about adverse effects on competition.

**1. The Internal Reorganization Raises No Horizontal Market Power Concerns**

The Internal Reorganization will not have an adverse impact on horizontal competition.

**a. No Change in Control Over Generation**

Section 33.3(a)(1) of the Commission's regulations provides that a horizontal competitive analysis is only required "if, as a result of the proposed transaction, a single corporate entity obtains ownership or control over the generating facilities of previously unaffiliated merging entities."<sup>40</sup> The Commission has consistently recognized that intra-affiliate reorganizations typically do not

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<sup>38</sup> See, e.g., 18 C.F.R. § 2.26; *Merger Policy Statement*, FERC Stats. & Regs. ¶ 31,044 at 30,116-24; Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,879.

<sup>39</sup> Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,879, 31,903.

<sup>40</sup> 18 C.F.R. § 33.3(a)(1).

raise horizontal competitive concerns,<sup>41</sup> and applicants seeking authorization for such reorganizations have not been required to submit a horizontal competitive analysis.<sup>42</sup>

Here, the Internal Reorganization involves an intra-corporate consolidation of two affiliated utilities, both of which are wholly owned, direct or indirect, subsidiaries of Duke Energy. As a result, the amount of generating capacity and/or transmission facilities owned or controlled by Applicants and their affiliates will not change as a result of the Internal Reorganization. Under the precedent described above, the proposed Internal Reorganization does not present the type of horizontal competitive impacts with which the Commission's FPA section 203 public interest analysis is concerned.<sup>43</sup>

For example, in 2013, NV Energy, Inc., together with its public utility operating companies Sierra Pacific Power Company ("Sierra") and Nevada Power Company ("Nevada Power"), sought Commission authorization for an internal reorganization pursuant to which Sierra would merge into Nevada Power and, post-reorganization, the two separate BAAs operated (respectively) by Sierra and Nevada Power would become a single BAA. In their application for FERC approval, the applicants noted that no competitive screen analysis was required under the Commission's regulations. Nevertheless, the applicants submitted an "abbreviated" competitive analysis focused on the effect of combining the BAAs. The Commission declined to make any findings with respect

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<sup>41</sup> See *Ameren Corp.*, 131 FERC ¶ 61,240 at P 18 (2010) (finding that an internal reorganization had no adverse effects on competition); *Cinergy Corp.*, 126 FERC ¶ 61,146 at P 32 (2009) ("Consistent with our precedent, we find that the Proposed Transaction is an internal corporate reorganization that will have no adverse effect on competition."), citing *Calpine Power Servs. Co.*, 92 FERC ¶ 61,150 at 64,187-88 (2000); *PP&L Res., Inc.*, 90 FERC ¶ 61,203 at 61,649 (2000); *Allegheny Energy Supply Co.*, 89 FERC ¶ 62,063 at 64,105 (1999); see also Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,902.

<sup>42</sup> See *NextEra*, 173 FERC ¶ 61,029; *NV Energy, Inc.*, 145 FERC 61,170 at P 26 (2013) ("NV Energy Order"); *Ameren Energy Generating Co.*, 106 FERC ¶ 63,011 at P 26 (citing Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,902), *aff'd in relevant part*, Opinion No. 473, 108 FERC ¶ 61,081 at P 64 (2004).

<sup>43</sup> Attachment 4, Affidavit of Ms. Julie R. Solomon at 1-2.

to the competitive analysis because it was not required to do so under the Commission's regulations.<sup>44</sup> Instead, the Commission concluded that the "internal reorganization of two utilities that are already affiliated will not result in any concentration in the generation markets and will not change the existing competitive incentives."<sup>45</sup>

Consistent with the NV Energy Order, the Commission should find that the proposed Internal Reorganization is an intra-affiliate consolidation that does not raise horizontal competitive concerns and does not require a horizontal competitive analysis. Nonetheless, the Applicants include as Attachment 4 an affidavit from Julie R. Solomon of Secretariat LLC explaining the lack of adverse horizontal impacts of the Internal Reorganization. Ms. Solomon also addresses generally the pro-competitive impacts that will result from consolidating three BAAs into a single BAA and the elimination of transmission seams between the three legacy BAAs.

**b. Cessation of Stub Mitigation**

In Section II.B above, the Companies explained that they are still complying with certain vestigial commitments from the Duke/Progress Merger. In particular, in the order approving the Duke/Progress Merger, the Commission ordered certain "Stub Mitigation" in the form of a limited set-aside of certain transmission capacity on the internal interface from the DEC BAA to the CPLE BAA, to be monitored by Potomac Economics, as well as requirements related to PARs and ATC on that path.<sup>46</sup> This Stub Mitigation will necessarily sunset with the combination of the three legacy BAAs. Specifically, once the interface between the DUK and CPLE BAAs ceases to exist, there will no longer be a DUK to CPLE path upon which to reserve a set-aside or operate PARs to

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<sup>44</sup> *NV Energy*, 145 FERC ¶ 61,170, at P 26.

<sup>45</sup> *Id.*

<sup>46</sup> June 2012 Merger Order, 139 FERC ¶ 61,194.

increase flows across. Instead, all transmission customers will be able to take network service throughout the combined BAA, and no Duke Energy affiliates will have a priority over any other transmission customers.

For most of the summer periods since the Stub Mitigation went into effect, it has been deemed by Potomac Economics to be “not necessary” because no Duke affiliates were making short-term or long-term firm transmission reservations over the DUK-to-CPLE path.<sup>47</sup> That was the case for short-term reservations for 2014, 2015, 2016, 2021, 2022, 2023, and 2024. Potomac Economics explained that for 2017, 2018, and 2020, there were certain short-term firm reservations by Duke affiliates, but they were renewals not covered by the Stub Mitigation commitment. For 2019, there was a single short-term firm reservation on the path, but there was “over 1000 MW of firm daily capacity” available, which was “more than adequate to meet the set aside requirement.”<sup>48</sup>

With respect to long-term firm transmission, the results were similar. For 2014, 2015, 2016, 2017, 2018, and 2019, no Duke affiliates made long-term firm requests for transmission on the path over the summer period.<sup>49</sup> For 2022, 2023, and 2024, “use of the set aside was not necessary” because there were “no confirmed or refused request[s]” on the path over the summer.<sup>50</sup> For 2020 and 2021, Duke affiliates made certain long-term firm requests on the path, but Potomac

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<sup>47</sup> See, e.g., 2024 Set-Aside Report at 4.

<sup>48</sup> Seasonal Independent Monitoring Report on “Stub Mitigation” Transmission Set-Aside for Duke Energy Corp. and Progress Energy, Inc., Docket No. EC11-60-004, at 5 (filed Sept. 26, 2019).

<sup>49</sup> The 2015 report explains that the IMM agreed to an exception for a certain transaction for summer 2014 that involved “redirection” of a reservation that would not use more ATC than an existing reservation. *Duke Energy Corp.*, Seasonal Independent Monitoring Report on “Stub Mitigation” Transmission Set-Aside for Duke Energy Corp. and Progress Energy, Inc., Docket No. EC11-60-004, at 5-6 (filed Sept. 30, 2015).

<sup>50</sup> See, e.g., 2024 Set-Aside Report at 4.

Economics confirmed that third-party requests exceeded the 129 MW, so the set-aside was satisfied.<sup>51</sup>

Although certain language in the Commission’s order approving the Duke/Progress Merger suggests that detailed market power analyses could be required to lift the Stub Mitigation, that is not the form of relief the Companies are seeking here. The Commission’s language in that order referred to a situation in which the Companies sought to eliminate the Stub Mitigation but otherwise operate as explained at that time (i.e., separately with the maintenance of an internal interface). The Internal Reorganization and its consolidation of BAAs simply renders the Stub Mitigation unnecessary because there will be no intra-BAA boundaries.

## **2. The Internal Reorganization Raises No Vertical Market Power Concerns**

The Internal Reorganization does not present any vertical market power concerns. The Commission’s regulations provide that a vertical market power analysis is only required “if, as a result of the Reorganization, a single corporate entity has ownership or control over one or more merging entities that provides inputs to electricity products and one or more merging entities that provides electric generation products . . . .”<sup>52</sup> Here, the Internal Reorganization will not result in Applicants owning or controlling any new entities that provide inputs to electricity products or any new entities that provide generation products.

Moreover, access to DEC’s and DEP’s respective transmission facilities will be governed under the Carolinas 1U OATT. Transmission access will thus continue to be available under a Commission-approved OATT, and the Internal Reorganization will not change the Commission’s

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<sup>51</sup> See, e.g., Seasonal Independent Monitoring Report on “Stub Mitigation” Transmission Set-Aside for Duke Energy Corp. and Progress Energy, Inc., Docket No. EC11-60-004, at 5 (filed Sept. 30, 2020).

<sup>52</sup> 18 C.F.R. § 33.4(a)(1).

authority to review the Carolinas 1U OATT upon consummation of the Internal Reorganization. The Commission has found that this is sufficient to address vertical market power concerns resulting from transmission ownership.<sup>53</sup>

***C. The Internal Reorganization Will Have No Adverse Effect on Regulation***

The Internal Reorganization will not have an adverse impact on regulation. As the Internal Reorganization pertains to federal regulation, Carolinas 1U, the surviving entity, will continue to be a “public utility” as defined in FPA section 201(e)<sup>54</sup> and will remain subject to the Commission’s jurisdiction.

The Internal Reorganization likewise will have no adverse effect on state regulation. Concurrent with this application, Applicants are filing applications with the NCUC and PSCSC for approval of the Internal Reorganization. As a result, the NCUC and PSCSC will have an opportunity to review the Internal Reorganization to ensure it is consistent with North Carolina and South Carolina law, respectively, and in the interest of North Carolina and South Carolina retail customers. Further, upon consummation of the Internal Reorganization, Carolinas 1U’s retail electric operations will continue to be subject to regulation by the NCUC and PSCSC. Consistent with Commission precedent, the Internal Reorganization will thus have no adverse effect on state regulation.<sup>55</sup>

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<sup>53</sup> See *EDF Dev., Inc.*, 126 FERC ¶ 61,141 at P 23 (2009); *Okla. Gas & Elec. Co.*, 124 FERC ¶ 61,239 at P 57 (2008).

<sup>54</sup> 16 U.S.C. § 824(e).

<sup>55</sup> See, e.g., *Madison Gas & Elec. Co.*, 106 FERC ¶ 61,098 at P 20 (2004); *Tex.-N.M. Power Co.*, 105 FERC ¶ 61,028 at P 22.

**D. The Internal Reorganization Will Not Result in the Cross-Subsidization, Pledge, or Encumbrance of Utility Assets**

Under section 203(a)(4) of the FPA and Section 2.26(f) of the Commission’s regulations,<sup>56</sup> the Commission considers whether a merger will result in a cross-subsidization of a non-utility associate company by a utility company or in a pledge or encumbrance of utility assets for the benefit of an associate company, and if so, whether the cross-subsidization, pledge, or encumbrance will be consistent with the public interest. Here, the Internal Reorganization falls within one of the Commission’s “safe harbors” identified in the *Supplemental Merger Policy Statement*,<sup>57</sup> such that detailed explanation and evidentiary support to demonstrate a lack of cross-subsidization is not required. Specifically, the Commission applies a “safe harbor” to “transactions that are subject to review by a state commission.”<sup>58</sup> As the Commission has explained,

The Commission, in the context of specific mergers or other corporate transactions, intends to defer to state commissions where the state adopts or has in place ring-fencing measures to protect customers against inappropriate cross-subsidization or the encumbrance of utility assets for the benefit of the “unregulated” affiliates. Therefore, compliance with Exhibit M could be satisfied with a showing that the Reorganization complies with specific state regulatory protections against inappropriate cross-subsidization by captive customers.<sup>59</sup>

The Internal Reorganization thus qualifies for a safe harbor for meeting the FPA section 203 cross-subsidization demonstration.<sup>60</sup> Nonetheless, Applicants submit Exhibit M to further address cross-subsidization issues.

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<sup>56</sup> 16 U.S.C. § 824b(a)(4); 18 C.F.R. § 2.26(f).

<sup>57</sup> *Supplemental Merger Policy Statement*, 120 FERC ¶ 61,060 at P 18.

<sup>58</sup> *Id.* at P 18.

<sup>59</sup> *Id.*

<sup>60</sup> *Id.* at P 16.

**VI. INFORMATION REQUIRED BY PART 33 OF THE COMMISSION'S REGULATIONS**

Pursuant to Section 33.2 of the Commission's regulations,<sup>61</sup> Applicants provide the following information:

**A. *Exact Name of Applicants and Addresses of Principal Business Offices (18 C.F.R. § 33.2(a))***

The exact legal names and addresses of the principal business offices of Applicants are:

Duke Energy Corporation  
525 South Tryon Street  
Charlotte, North Carolina 28202

Duke Energy Progress, LLC  
410 South Wilmington Street  
Raleigh, North Carolina 27602

Duke Energy Carolinas, LLC  
525 South Tryon Street  
Charlotte, North Carolina 28202

**B. *Names and Addresses of the Persons Authorized to Receive Notices and Communications in Respect to Applicants (18 C.F.R. § 33.2(b))***

The names and addresses of persons authorized to receive notice and communications with respect to this application are:

Heather Horne  
Associate General Counsel  
Duke Energy Corporation  
1301 Pennsylvania Ave. NW, Suite 200  
Washington, DC 20004  
(202) 824-8009  
heather.horne@duke-energy.com

Christopher R. Jones  
TROUTMAN PEPPER LOCKE LLP  
401 9th Street, NW, Suite 1000  
Washington, DC 20004  
(202) 662-2181  
chris.jones@troutman.com

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<sup>61</sup> 18 C.F.R. § 33.2. The Commission has previously relaxed the full filing requirements of Part 33 of its regulations and allowed the filing of only such information as required to satisfy the minimum statutory requirements of FPA section 203. *See, e.g., FirstEnergy Solutions Corp.*, 170 FERC ¶ 61,096 at P 81 n.111 (2020). This application provides the Commission with the information necessary to determine that the Proposed Transaction is consistent with the public interest and will not adversely affect competition, rates, or regulation or raise cross-subsidization issues.

**C. Description of the Applicants and the Other Parties to the Internal Reorganization (18 C.F.R. § 33.2(c))**

**1. Business Activities of Applicants (Exhibit A) (18 C.F.R. § 33.2(c)(1))**

The business activities of Applicants are described in Section II.A of this application. Therefore, Applicants request a waiver of the requirement to file a separate Exhibit A.<sup>62</sup>

**2. Energy Subsidiaries and Energy Affiliates and Their Business Activities (Exhibit B) (18 C.F.R. § 33.2(c)(2))**

The Applicants' primary business is described in Section II.A. Applicants' subsidiaries and affiliates are not impacted by the Internal Reorganization, as it only applies to DEC and DEP. Applicants therefore request waiver of the need to provide any additional information in a separate Exhibit B under Section 33.2(c)(2).<sup>63</sup>

**3. Organizational Charts (Exhibit C) (18 C.F.R. § 33.2(c)(3))**

In Exhibit C, Applicants are providing pre- and post-Internal Reorganization corporate organization charts.

**4. Description of All Joint Ventures, Strategic Alliances, Tolling Arrangements or Other Business Arrangements, Including Transfers of Operational Control of Transmission Facilities to Commission Approved Regional Transmission Organizations, Both Current, and Planned to Occur within a Year from the Date of Filing, to Which the Applicants or Their Parent Companies, Energy Subsidiaries, and Energy Affiliates Are Parties, Unless the Applicants Demonstrate That the Internal Reorganization Does Not Affect any of Their Business Interests (Exhibit D) (18 C.F.R. § 33.2(c)(4))**

Except as set forth in this application, the Internal Reorganization will have no effect on any current or planned joint ventures, strategic alliances, or other business arrangements of

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<sup>62</sup> See, e.g., *IIF US Holding LP*, 173 FERC ¶ 61,232 at P 56 (2020).

<sup>63</sup> *Id.*

Applicants or their parent companies, energy subsidiaries, and energy affiliates. Therefore, Applicants request a waiver of the requirement to file a separate Exhibit D.<sup>64</sup>

**5. Common Officers or Directors (Exhibit E) (18 C.F.R. § 33.2(c)(5))**

The Internal Reorganization will not affect the officers and directors of the Companies' parent company, Duke Energy. As such, Applicants request waiver of the need to provide a list of common officers and directors. While DEC and DEP may share some common officers and directors, that is not germane to the Commission's FPA section 203 analysis.

**6. Description of Customers (Exhibit F) (18 C.F.R. § 33.2(c)(6))**

Exhibit F includes a list of Applicants' wholesale power customers and unbundled transmission services customers.

***D. Description of Jurisdictional Facilities Owned, Operated, or Controlled by the Applicants or Their Parent Companies, Subsidiaries, Affiliates, and Associate Companies (Exhibit G) (18 C.F.R. § 33.2(d))***

See Section II.A, above, for a description of the jurisdictional facilities affected by the Internal Reorganization. Applicants therefore request waiver of the requirement to provide a separate listing of jurisdictional facilities owned by Duke Energy affiliates in a separate Exhibit G.

***E. Narrative Description of the Reorganization (Exhibit H) (18 C.F.R. § 33.2(e))***

**1. The Identities of All Parties Involved in the Internal Reorganization (18 C.F.R. § 33.2(e)(1))**

A narrative description of the Internal Reorganization is included in Section IV of this application, including identification of the parties involved in the Internal Reorganization.

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<sup>64</sup> See, e.g., *PNM Res., Inc.*, 124 FERC ¶ 61,019 at PP 50-54 (2008).

**2. All Jurisdictional Facilities and Securities Associated with or Affected by the Internal Reorganization; consideration for the Internal Reorganization; effect of the Internal Reorganization on jurisdictional facilities and securities (18 C.F.R. § 33.2(e)(2) – (e)(4))**

The jurisdictional facilities and securities associated with or affected by the Internal Reorganization, the effect of the Internal Reorganization on such facilities and securities, and the consideration for the Internal Reorganization are described in Section IV of this application and/or Exhibit I. Accordingly, Applicants respectfully request waiver of the need to submit a separate Exhibit H.

***F. All Contracts Relating to the Internal Reorganization Together with Copies of All Other Written Instruments Entered into or Proposed to Be Entered into by the Parties to the Internal Reorganization (Exhibit I) (18 C.F.R. § 33.2(f))***

The Internal Reorganization will be effectuated pursuant to the Merger Agreement, a Contribution Agreement, and Articles of Merger. Forms of those documents, which will be substantively the same as the final versions that will be executed to consummate the Internal Reorganization, are attached as Exhibit I.<sup>65</sup>

***G. A Statement Explaining the Facts Relied upon to Demonstrate That the Internal Reorganization Is Consistent with the Public Interest (Exhibit J) (18 C.F.R. § 33.2(g))***

The facts relied upon to demonstrate that the Internal Reorganization is consistent with the public interest are described in Section V of this application. Accordingly, Applicants request a waiver of the requirement to file a separate Exhibit J.

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<sup>65</sup> Pursuant to Order No. 642, the undersigned counsel for Applicants certify that, to the best of their knowledge, the final agreements will reflect the terms and conditions contained in the forms of agreement attached as Exhibit I in all material respects. See Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,877.

***H. Map (Exhibit K) (18 C.F.R. § 33.2(h))***

Exhibit K includes a map showing the current service territories of DEP and DEC, currently spanning three separate BAAs. Exhibit K also includes a map showing the combined service territories of DEP and DEC in a single, post-Internal Reorganization, combined BAA.

***I. Other Regulatory Approvals (Exhibit L) (18 C.F.R. § 33.2(i))***

As discussed in Section V.C of this application, the Companies are seeking regulatory approvals for the Internal Reorganization from the NCUC and the PSCSC. In addition to seeking regulatory approval from the NCUC and PSCSC, the Companies will make a filing with the Nuclear Regulatory Commission to transfer DEP's nuclear licenses to DEC, as well as a separate FERC filing to transfer DEP's existing hydro licenses to DEC.

***J. Cross-Subsidization (Exhibit M) (18 C.F.R. § 33.2(j)(1), (2))***

The facts relied upon to demonstrate that the Internal Reorganization will not result in cross-subsidization of a non-utility associate company or pledge or encumbrance of utility assets for the benefit of an associate company are provided in Section V.D above and in Exhibit M.

***K. Proposed Accounting Entries (18 C.F.R. § 33.5)***

Applicants have provided proposed accounting entries in Attachment 5. Applicants will provide final accounting entries within six months of closing if directed by the Commission, and those accounting submissions will be company-specific and provide all the accounting entries and amounts related to the Internal Reorganization along with narrative explanations describing the basis for the entries.

***L. Verification (18 C.F.R. § 33.7)***

Pursuant to Section 33.7 of the Commission's regulations, a signed verification by a person having authority with respect thereto and having knowledge of the matters set forth in this application is included as Attachment 6.

**VII. OTHER MATERIALS**

In addition to the information described above and included in Exhibits required by Commission regulations, Applicants include as attachments the following:

- Attachment 1 – Prepared Direct Testimony of Nelson Peeler
- Attachment 2 – Prepared Direct Testimony of Jennifer S. Ellis
- Attachment 3 – Prepared Direct Testimony of Blain Atkins
- Attachment 4 – Affidavit and Supporting Materials of Ms. Julie R. Solomon
- Attachment 5 – Accounting Entries
- Attachment 6 – Verification

**VIII. CONCLUSION**

As demonstrated in this application, including the attached Exhibits and Attachments, the Internal Reorganization is consistent with the public interest under the standards for public interest findings set forth in the Commission's *Merger Policy Statement* and Part 33 of the Commission's regulations. Accordingly, Applicants respectfully request that the Commission authorize the Internal Reorganization under FPA section 203 as consistent with the public interest. Applicants also respectfully request that the Commission grant waivers of the Commission's regulations as described herein or to the extent necessary to grant this application.

*[Signatures Follow]*

Respectfully submitted,

*/s/ Heather Horne*

\_\_\_\_\_  
Heather Horne  
Associate General Counsel  
Duke Energy Corporation  
1301 Pennsylvania Ave. NW, Suite 200  
Washington, DC 20004  
(202) 824-8009  
heather.horne@duke-energy.com

*/s/ Christopher R. Jones*

\_\_\_\_\_  
Christopher R. Jones  
TROUTMAN PEPPER LOCKE LLP  
401 9th Street NW, Suite 1000  
Washington, DC 20004  
(202) 274-2881  
chris.jones@troutman.com

*Counsel to Duke Energy Corporation, Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC*

## Exhibit C

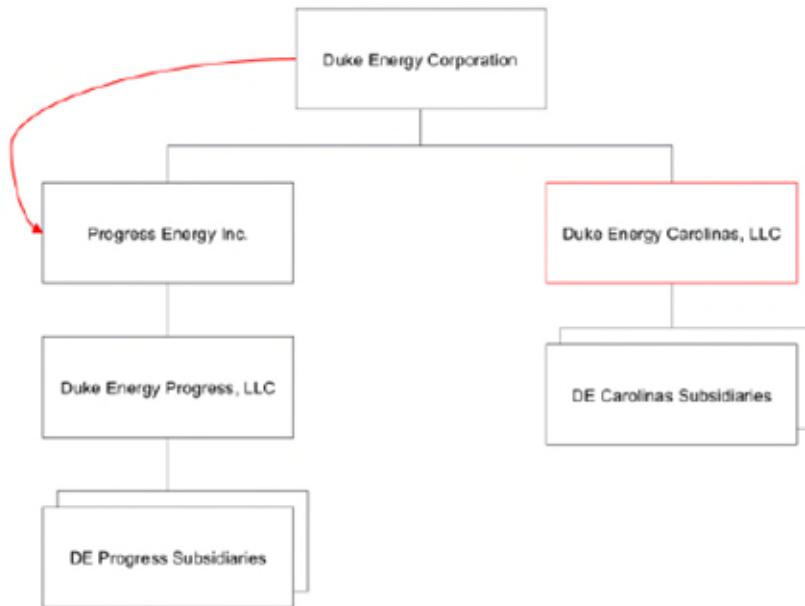
### Pre- and Post-Transaction Corporate Organization Charts

#### DEC/DEP COMBINATION: SIMPLIFIED SCHEMATIC ILLUSTRATING TRANSACTION STEPS AND RESULTING CORPORATE STRUCTURE

### Step 1: Contribute DE Carolinas to Progress Energy

Duke Energy Corporation contributes Duke Energy Carolinas, LLC ("DE Carolinas") to Progress Energy, Inc. ("Progress Energy"). Date: January 1, 2027 (assuming timely regulatory approval).

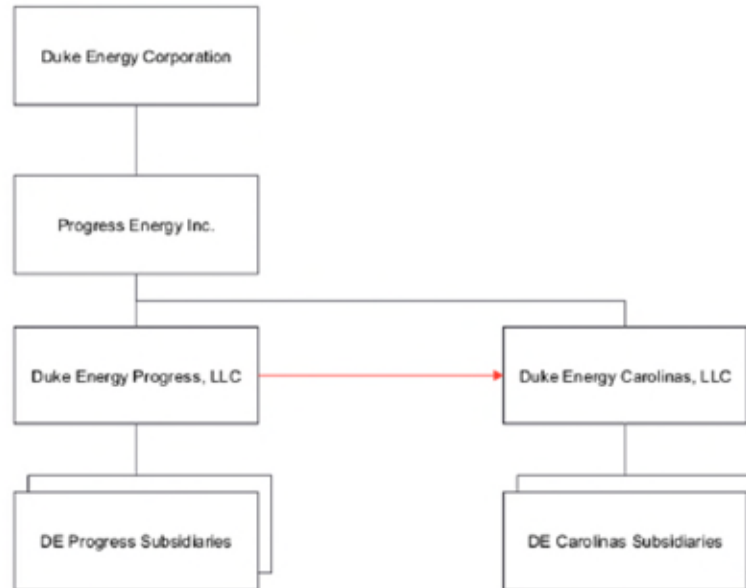
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## Step 2: Merger of DE Progress into DE Carolinas

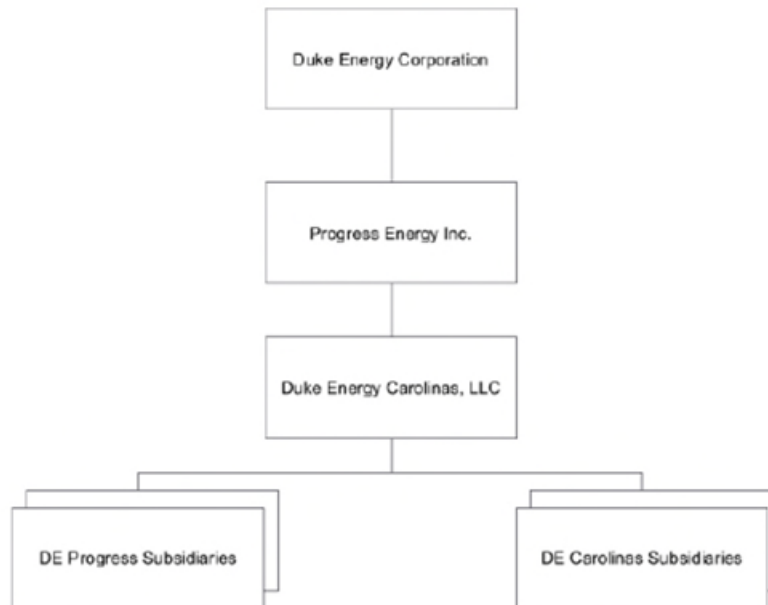
Duke Energy Progress, LLC (“**DE Progress**”) merges into Duke Energy Carolinas, LLC (“**DE Carolinas**”), with DE Carolinas surviving. Date: January 1, 2027 (assuming timely regulatory approval).

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# Abbreviated Structure – Post-1U Transaction

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**Exhibit F**  
**Description of Customers**  
Joint OATT Customers

<u>DEC</u>	<u>DEP</u>
Brookfield Renewable Trading and Marketing LP Carolina Power & Light Carolina Power Partners, LLC North Carolina Electric Membership Corporation South Carolina Public Service Authority - P2P City of Orangeburg, South Carolina Blue Ridge Electric Membership Corporation Central Electric Power Cooperative, Inc. City of Concord, North Carolina City of Kings Mountain, North Carolina City of Seneca, South Carolina South Carolina Electric & Gas Company EnergyUnited Electric Membership Corporation Greenwood Commissioners of Public Works Haywood Electric Membership Corporation Lockhart Power Company Macquarie Energy LLC North Carolina Municipal Power Agency Number 1 New River Light and Power Company Piedmont Electric Membership Corporation Piedmont Municipal Power Agency Rutherford Electric Membership Corporation Southern Power Company - Rowan Plant Town of Dallas, North Carolina Town of Due West, South Carolina Town of Forest City, North Carolina Town of Highlands, North Carolina United States Department of Energy Western Carolina University	North Carolina Electric Membership Corporation City of Camden, South Carolina French Broad Electric Membership Corporation Haywood Electric Membership Corporation North Carolina Eastern Municipal Power Agency Piedmont Electric Membership Corporation Public Works Commission of the City of Fayetteville Town of Black Creek, North Carolina Town of Lucama, North Carolina Town of Sharpsburg, North Carolina Town of Stantonsburg, North Carolina Town of Waynesville, North Carolina Town of Winterville, North Carolina Uwharrie Mountain Renewable Energy Craven County Wood Energy

Wholesale Power Supply Customers

<u>DEC</u>	<u>DEP</u>
Blue Ridge Electric Membership Corporation Rutherford Electric Membership Corporation Haywood Electric Membership Corporation Central Electric Power Cooperative, Inc. City of Orangeburg, South Carolina Lockhart Power Company Town of Dallas, North Carolina Town of Due West, South Carolina Town of Forest City, North Carolina Town of Highlands, North Carolina North Carolina Electric Membership Corporation Piedmont Electric Membership Corporation	Haywood Electric Membership Corporation Fayetteville Public Works Commission French Broad Electric Membership Cooperative North Carolina Eastern Municipal Power Agency North Carolina Electric Membership Corporation Piedmont Electric Membership Corporation

**Exhibit I**

**Agreement and Plan of Merger, Contribution Agreement, and Articles of Merger**

## AGREEMENT AND PLAN OF MERGER

THIS AGREEMENT AND PLAN OF MERGER (as amended, restated, supplemented or modified from time to time, this “Agreement”), is entered into as of [January 1, 2027], by and among Duke Energy Corporation, a Delaware corporation (“Parent”), Progress Energy, Inc., a North Carolina corporation (“Progress”), Duke Energy Carolinas, LLC, a North Carolina limited liability company (“DEC”), and Duke Energy Progress, LLC, a North Carolina limited liability company (“DEP”). Each of Parent, Progress, DEC and DEP are referred to herein individually as a “Party”, and collectively, as the “Parties”.

### RECITALS

WHEREAS, Progress is a wholly-owned direct subsidiary of Parent;

WHEREAS, DEP is a wholly-owned indirect subsidiary of Parent, with Progress being the sole member and holder of 100% of the issued and outstanding ownership interests in DEP;

WHEREAS, immediately prior to the execution of this Agreement, DEC was a wholly-owned direct subsidiary of Parent and Parent was the sole member and holder of 100% of the issued and outstanding ownership interests in DEC;

WHEREAS, [immediately prior to the execution of this Agreement], Parent and Progress have entered into a Contribution Agreement, pursuant to which Parent has contributed all of its ownership interests in DEC to Progress (the “Contribution”);

WHEREAS, after giving effect to the Contribution and at the time of execution of this Agreement, (a) DEC is a (i) wholly-owned direct subsidiary of Progress and (ii) wholly-owned indirect subsidiary of Parent, and (b) Progress is the sole member and holder of 100% of the issued and outstanding ownership interests in DEC;

WHEREAS, prior to the Merger Effective Time (as defined below), the Board of Directors of each of Parent, Progress, DEC and DEP, as applicable, (i) has declared it advisable and determined that it is in the best interests of each such Party, as applicable, to pursue, and has authorized and approved, for valid business purposes, a restructuring of certain of its direct and indirect subsidiaries, including Progress, DEC and DEP, as applicable (the “Restructuring”), and the transactions contemplated thereunder, and (ii) has adopted and approved the execution, delivery and performance by each such Party, as applicable, of the Restructuring and the transactions contemplated thereunder, including this Agreement, the Contribution Agreement and the consummation of the Merger (as defined below) and the Contribution;

WHEREAS, prior to the Merger Effective Time, Parent, through DEC and DEP, has provided applicable notice to or obtained applicable approval of the Federal Energy Regulatory Commission, the North Carolina Utilities Commission, and the Public Service Commission of South Carolina with respect to the Restructuring and the transactions contemplated thereunder;

WHEREAS, as part of the Restructuring, the Parties hereto desire to enter into this Agreement pursuant to which DEP will be merged with and into DEC, with DEC surviving such Merger; and

WHEREAS, it is intended that the Merger shall qualify as a “reorganization” within the meaning of Section 368(a) of the Internal Revenue Code of 1986, as amended (the “Code”), and that this

Agreement is intended to be and is adopted as a plan of reorganization for the purposes of Sections 354 and 361 of the Code.

NOW, THEREFORE, in consideration of the foregoing and the mutual covenants and agreements herein contained, the receipt and sufficiency of which hereby are acknowledged, and intending to be legally bound, the Parties hereto hereby agree as follows:

### **AGREEMENT**

1. Subject to the terms and conditions contained herein, at the Merger Effective Time, DEP shall be merged with and into DEC (the "Merger"), in accordance with Section 57D-9 of the North Carolina Limited Liability Company Act (the "Act"), and DEC shall be the surviving entity (hereinafter sometimes referred to as the "Surviving Entity") and shall continue to exist as the Surviving Entity under its present name pursuant to the provisions of the Act. The separate existence of DEP (hereinafter sometimes referred to as the "Merging Entity") shall cease upon the effective time of the Merger in accordance with the provisions of the Act. The Merger shall become effective at such time as the Articles of Merger are duly filed with the Secretary of State of the State of North Carolina or at such later time as is specified in the Articles of Merger (the time the Merger becomes effective being hereinafter referred to as the "Merger Effective Time").

2. The Articles of Organization of DEC as of the Merger Effective Time will continue to be the Articles of Organization of the Surviving Entity and will continue in full force and effect until changed, altered or amended as therein provided and in the manner prescribed by the provisions of the Act.

3. The Operating Agreement of DEC as of the Merger Effective Time will continue to be the Operating Agreement of the Surviving Entity and will continue in full force and effect until changed, altered or amended as therein provided and in the manner prescribed by the provisions of the Act.

4. [The members, directors and/or officers of DEC on the Merger Effective Time shall be the members, directors and/or officers of the Surviving Entity, respectively, all of whom will hold their membership, positions and/or offices until the election and qualification of their respective successors or until their tenure is otherwise terminated in accordance with the Operating Agreement of the Surviving Entity.]

5. Each ownership interest of DEC as of the Merger Effective Time will continue as the ownership interests of the Surviving Entity. The ownership interests of the Merging Entity as of the Merger Effective Time shall, upon the Merger Effective Time, be cancelled and cease to exist and no payment shall be made with respect thereto.

6. In the event that the Merger has been fully authorized in accordance with the provisions of the Act, the Merging Entity and the Surviving Entity hereby stipulate that they will cause to be executed and filed and/or recorded any document or documents prescribed by the laws of the State of North Carolina, and that they will cause to be performed all necessary acts therein and elsewhere to effectuate the Merger.

7. Each of Parent and Progress, as the direct or indirect sole member of the Surviving Entity, shall be authorized to execute and file with the Secretary of State of the State of North Carolina the Articles of Merger on behalf of the Surviving Entity in conformity with the provisions of the Act. Each of Parent and Progress, as the direct or indirect sole member of the Surviving Entity and the Merging Entity, respectively, shall be authorized, empowered, and directed to do any and all acts and

things, and to make, execute, deliver, file, and/or record any and all instruments, papers, and documents which will be or become necessary, proper, or convenient to carry out or put into effect any of the provisions of this Agreement or the Merger.

8. The Parties intend that the Merger shall qualify as a “reorganization” within the meaning of Section 368(a) of the Code, and that this Agreement is intended to be and is adopted as a plan of reorganization for the purposes of Sections 354 and 361 of the Code.

9. Notwithstanding the approval and adoption by the Parties of the Restructuring and the transactions contemplated thereunder, this Agreement may be amended or terminated and the Merger and the Contribution may be abandoned by Parent at any time prior to the Merger Effective Time.

10. If, at any time after the Restructuring, DEC, as the Surviving Entity, determines, in its sole discretion, or is advised, that any documents (including any deeds, bills of sale or instruments of conveyance), assignments, assurances or any other actions or things are necessary or desirable to vest, perfect or confirm or record or otherwise vest in DEC its right, title and interest in, to or under any of the rights, properties or assets of DEP acquired or to be acquired by DEC as a result of, or in connect with, the Merger, then the officers and directors of DEC will be, and hereby are, authorized to execute and deliver, in the name and on behalf of DEP, all such deeds, bills of sale, instruments of conveyance, assignments and assurances, and to take and do, in the name and on behalf of, each of such companies or otherwise, all such other actions and things as may be necessary or desirable to vest, perfect or confirm any and all right, title or interest in, to and under such rights, properties or assets in DEC or otherwise to carry out the terms, conditions or intent of the Restructuring and the transactions contemplated thereunder, including this Agreement and the Contribution Agreement.

11. This Agreement shall be governed by, and construed and enforced in accordance with, the laws of the State of North Carolina, without regard to the choice of law provisions thereof.

12. This Agreement, and any amendment, restatement, supplement or other modification hereto or waiver hereunder, may be executed in counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument.

*[Remainder of page intentionally left blank; Signature page follows.]*

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their respective officers or authorized signatories thereunto duly authorized, as of the date first set forth above.

PARENT:

**Duke Energy Corporation**

By: \_\_\_\_\_  
Name:  
Title:

PROGRESS:

**Progress Energy, Inc.**

By: \_\_\_\_\_  
Name:  
Title:

DEC:

**Duke Energy Carolinas, LLC**

By: \_\_\_\_\_  
Name:  
Title:

DEP:

**Duke Energy Progress, LLC**

By: \_\_\_\_\_  
Name:  
Title:

## CONTRIBUTION AGREEMENT

THIS CONTRIBUTION AGREEMENT (this “Agreement”) is made and entered into as of [January 1, 2027], by and between Duke Energy Corporation, a Delaware corporation (“Duke”), and Progress Energy, Inc., a North Carolina corporation (“Progress”).

### RECITALS

**WHEREAS**, Progress is a wholly-owned direct subsidiary of Duke;

**WHEREAS**, Duke is the sole member of and owns 100% of the issued and outstanding ownership interests (the “DEC Interests”) in Duke Energy Carolinas, LLC, a North Carolina limited liability company (“DEC”);

**WHEREAS**, Progress is the sole member of and owns 100% of the issued and outstanding ownership interests in Duke Energy Progress, LLC, a North Carolina limited liability company (“DEP”);

**WHEREAS**, prior to the Effective Time (as defined below), the Board of Directors of each of Duke, Progress, DEC and DEP, as applicable, (i) has declared it advisable and determined that it is in the best interests of each such party, as applicable, to pursue, and has authorized and approved, for valid business purposes, a restructuring of certain of its direct and indirect subsidiaries, including Progress, DEC and DEP, as applicable (the “Restructuring”), and the transactions contemplated thereunder, and (ii) has adopted and approved the execution, delivery and performance by each such party, as applicable, of the Restructuring and the transactions contemplated thereunder, including this Agreement, the Merger Agreement (as defined below) and the consummation of the Contribution (as defined below) and the Merger (as defined below);

**WHEREAS**, prior to the Effective Time, Duke, through DEC and DEP, its wholly-owned direct or indirect subsidiaries, has provided applicable notice to or obtained applicable approval of the Federal Energy Regulatory Commission, the North Carolina Utilities Commission, and the Public Service Commission of South Carolina with respect to the Restructuring and the transactions contemplated thereunder;

**WHEREAS**, as part of the Restructuring and pursuant to this Agreement, Duke desires to contribute, assign, transfer and convey to Progress all of Duke’s rights, interests and obligations that may be allocable in and to the DEC Interests (the “Contribution”), such that, as of the Effective Time, DEC becomes a wholly-owned direct subsidiary of Progress;

**WHEREAS**, as part of the Restructuring and pursuant to this Agreement, Progress desires to accept Duke’s Contribution and acquire and assume all of Duke’s rights, interests and obligations allocable or attributable in and to the DEC Interests on the terms and conditions set forth herein; and

**WHEREAS**, Duke and Progress intend that the Contribution as provided herein shall constitute a transaction subject to the provisions of Section 351 of the United States Internal Revenue Code of 1986, as amended (the “Code”).

**NOW, THEREFORE**, in consideration of the foregoing and of the mutual promises and covenants contained in this Agreement, and intending to be legally bound, the parties hereto hereby agree as follows:

## AGREEMENT

1. Effective as of the Effective Time, Duke hereby contributes, assigns, transfers and conveys to Progress all of Duke's rights, interests and obligations that may be allocable in and to the DEC Interests, and Progress hereby accepts Duke's Contribution and acquires and assumes all of Duke's rights, interests and obligations allocable or attributable in and to the DEC Interests.

2. The Contribution, deliveries and other transactions contemplated hereunder shall become effective as of [January 1, 2027] at [●] Eastern Time (the "Effective Time").

3. This Agreement shall be governed by, and construed and enforced in accordance with, the laws of the State of North Carolina, without regard to the choice of law provisions thereof.

4. This Agreement may be executed in counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument.

5. This Agreement shall be binding upon, and shall inure to the benefit of, the parties' respective heirs, representatives, successors and assigns.

6. Duke and Progress intend that the Contribution as provided herein shall constitute a transaction subject to the provisions of Section 351 of the Code.

*[Signature page follows.]*

IN WITNESS WHEREOF, the parties hereto have executed this Contribution Agreement as of the date first set forth above.

**Duke Energy Corporation**

By: \_\_\_\_\_  
Name:  
Title:

**Progress Energy, Inc.**

By: \_\_\_\_\_  
Name:  
Title:

*State of North Carolina  
Department of the Secretary of State*

**ARTICLES OF MERGER**

Pursuant to North Carolina General Statute Sections 55-11-05(a), 55-11-12, 55A-11-09(d), 55A-11-04, 57D-9-42, 59-73.32(a) and 59-1072(a), as applicable, the undersigned entity does hereby submit the following Articles of Merger as the surviving business entity in a merger between two or more business entities.

1. The name of the surviving entity is **Duke Energy Carolinas, LLC**, a limited liability company organized under the laws of North Carolina.

2. The physical and mailing address of the surviving entity is:

Physical Address:

525 South Tryon Street  
Charlotte, North Carolina 28202  
Mecklenburg County

Mailing Address:

525 South Tryon Street  
Charlotte, North Carolina 28202  
Mecklenburg County

3. The name of the merging entity is **Duke Energy Progress, LLC**, a limited liability company organized under the laws of North Carolina.

4. The physical and mailing address of the merging entity is:

Physical Address:

411 Fayetteville Street  
Raleigh, North Carolina 27601  
Wake County

Mailing Address:

525 South Tryon Street  
Charlotte, North Carolina 28202  
Mecklenburg County

5. The mailing address of the surviving entity prior to the merger shall be the mailing address of the surviving entity after giving effect to the merger.

6. No amendments to the surviving entity's Articles of Organization are necessary as a result of the merger, and as such, the surviving entity's Articles of Organization, as currently filed with the Secretary of State of the State of North Carolina, shall be the Articles of Organization of the surviving entity, upon the effective time of these articles set forth below.

7. A Plan of Merger has been duly approved in the manner required by law by each of the business entities participating in the merger.

8. These articles will be effective at [●] Eastern Time on [the date these articles are filed by the Secretary of State] [OR] [January 1, 2027].

This the [1<sup>st</sup>] day of [January], [2027].

**DUKE ENERGY CAROLINAS, LLC**

By: \_\_\_\_\_

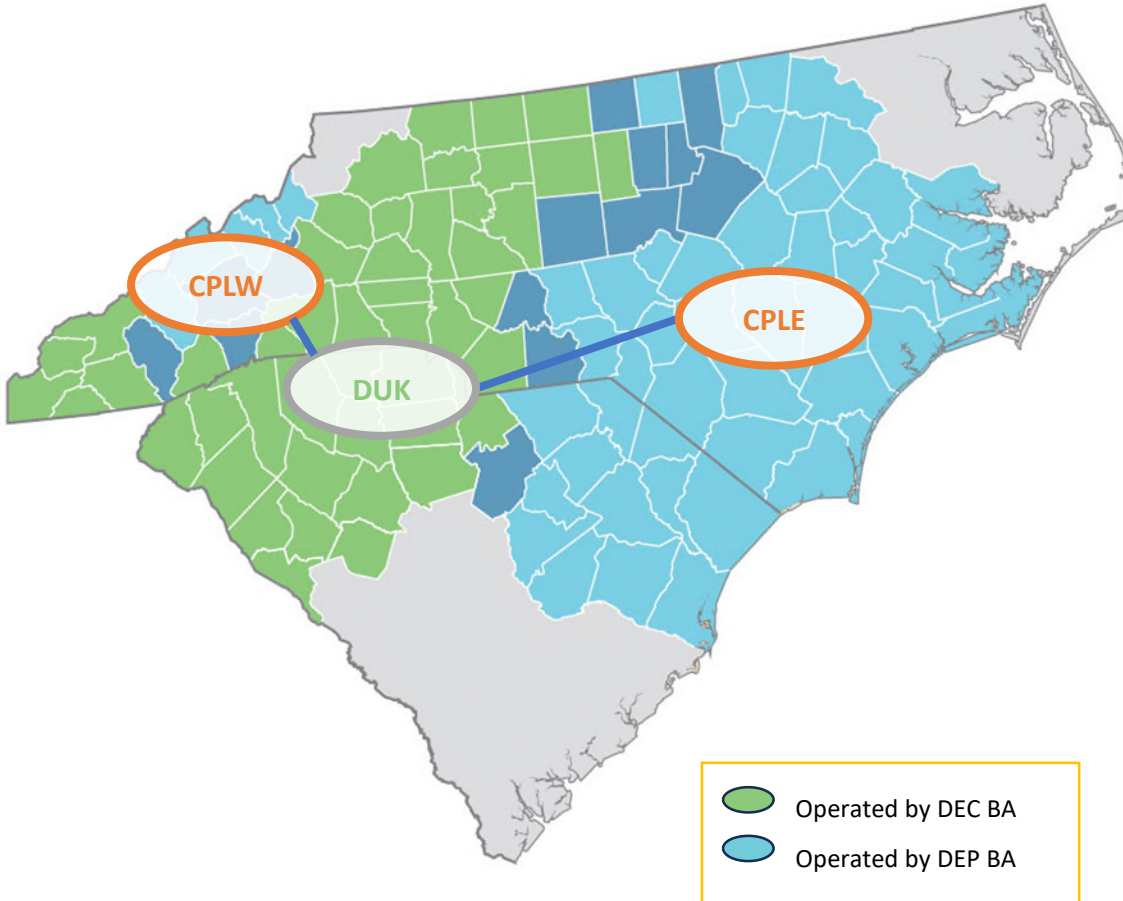
Name:

Title:

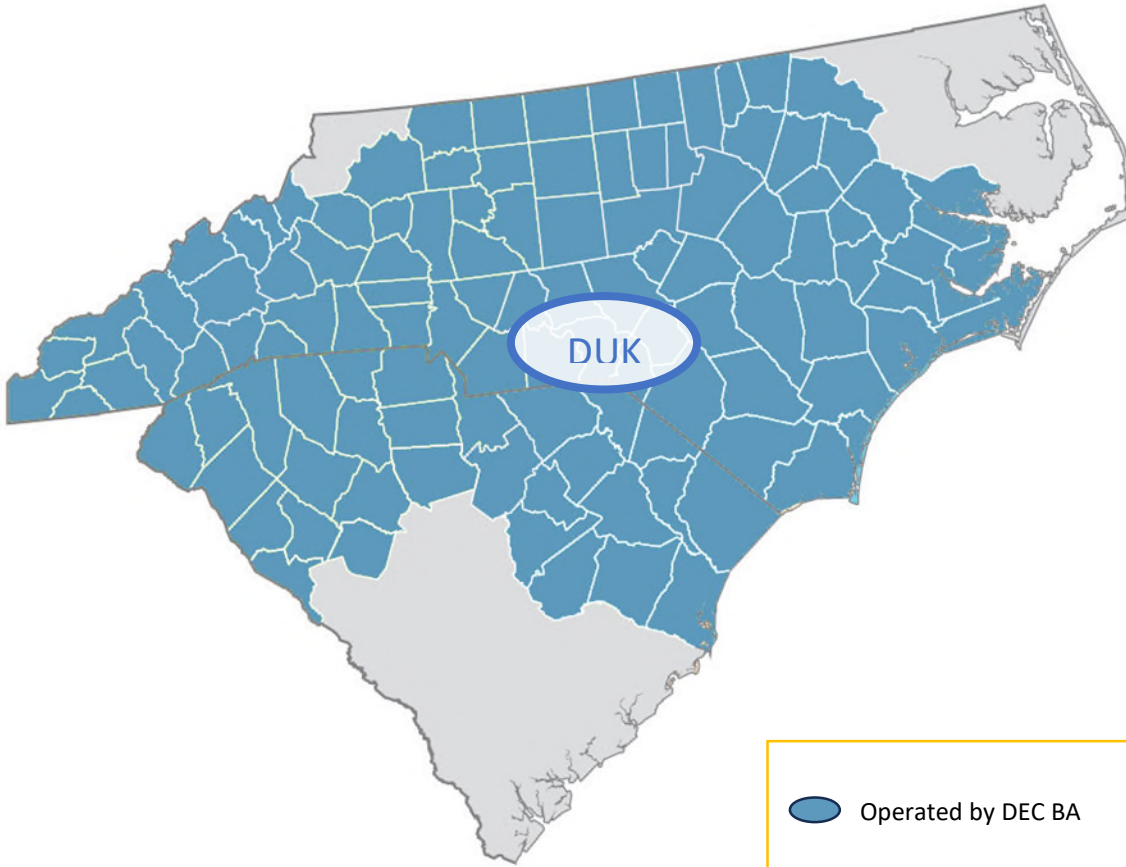
## Exhibit K

### Maps of Current and Post-Internal Reorganization Service Territories

#### Current Service Territories



## Combined Service Territory Post-Internal Reorganization



## **Exhibit L**

### **Other Regulatory Approvals**

Applicants are also requesting authorization of the Internal Reorganization from the North Carolina Utilities Commission and the Public Service Commission of South Carolina. In addition to seeking regulatory approval from the NCUC and PSCSC, the Companies will make a filing with the Nuclear Regulatory Commission to transfer DEP's nuclear licenses to DEC, as well as a separate FERC filing to transfer DEP's existing hydro licenses to DEC.

## **Exhibit M**

### **Cross-Subsidization**

Under section 203(a)(4) of the FPA and Section 2.26(f) of the Commission’s regulations,<sup>1</sup> the Commission considers whether a merger will result in a cross-subsidization of a non-utility associate company by a utility company or in a pledge or encumbrance of utility assets for the benefit of an associate company, and if so, whether the cross-subsidization, pledge, or encumbrance will be consistent with the public interest. Here, the Internal Reorganization falls within one of the Commission’s “safe harbors” identified in the *Supplemental Merger Policy Statement*,<sup>2</sup> such that detailed explanation and evidentiary support to demonstrate a lack of cross-subsidization is not required. Specifically, the Commission applies a “safe harbor” to “transactions that are subject to review by a state commission.”<sup>3</sup> As the Commission has explained,

The Commission, in the context of specific mergers or other corporate transactions, intends to defer to state commissions where the state adopts or has in place ring-fencing measures to protect customers against inappropriate cross-subsidization or the encumbrance of utility assets for the benefit of the “unregulated” affiliates. Therefore, compliance with Exhibit M could be satisfied with a showing that the Reorganization complies with specific state regulatory protections against inappropriate cross-subsidization by captive customers.<sup>4</sup>

The Internal Reorganization will be subject to review and approval of the North Carolina Utilities Commission and the Public Service Commission of South Carolina and thus qualifies for

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<sup>1</sup> 18 C.F.R. § 2.26(f).

<sup>2</sup> *Supplemental Merger Policy Statement*, 120 FERC ¶ 61,060.

<sup>3</sup> *Id.* at P 18.

<sup>4</sup> *Id.*

this safe harbor for meeting the FPA section 203 cross-subsidization demonstration.<sup>5</sup> Nonetheless, Applicants submit this Exhibit M to further address cross-subsidization issues.

Mergers of two regulated franchised public utilities regulated by this Commission and State Commissions are not the type of transactions that give rise to cross-subsidy issues. In accordance with Section 33.2(j)(1)(ii) of the Commission’s regulations, except as described in the body of the application, Applicant verifies that the Internal Reorganizations will not result in: (1) any transfer of facilities between a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, and an associate company; (2) any new issuance of securities by a traditional public utility associate company that has captive customers or that owns, or provides transmission service over, jurisdictional transmission facilities, for the benefit of an associate company; (3) any new pledge or encumbrance of assets of a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company; or (4) any new affiliate contract between a non-utility associate company and a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, other than non-power goods and services agreements subject to review under FPA sections 205 and 206.

To the extent that DEC and DEP are considered “associate companies” of each other for Exhibit M purposes, the transfer of facilities and consummation of the Internal Reorganization is consistent with the public interest for the reasons described in the body of the application. DEP will merge its jurisdictional facilities with and into DEC but the result will be a single regulated

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<sup>5</sup> *Id.* at P 16.

utility subject to the same regulatory oversight for purposes of avoiding any undue cross-subsidization.

**Attachment 1**

**Prepared Direct Testimony of Nelson Peeler**

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

**Duke Energy Corporation )  
Duke Energy Carolinas, LLC )  
Duke Energy Progress, LLC )**

**Docket No. EC25-\_\_\_\_-000**

**PREPARED DIRECT TESTIMONY OF  
NELSON PEELER  
ON BEHALF OF  
DUKE ENERGY CORPORATION,  
DUKE ENERGY CAROLINAS, LLC AND  
DUKE ENERGY PROGRESS, LLC**

**August 14, 2025**

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

**Duke Energy Corporation** )  
**Duke Energy Carolinas, LLC** ) **Docket No. EC25-\_\_\_\_-000**  
**Duke Energy Progress, LLC** )

**PREPARED DIRECT TESTIMONY OF  
NELSON PEELER  
ON BEHALF OF  
DUKE ENERGY CORPORATION,  
DUKE ENERGY CAROLINAS, LLC AND  
DUKE ENERGY PROGRESS, LLC**

1 **I. INTRODUCTION AND PURPOSE**

2 **Q. Please state your name and business address.**

3 A. My name is V. Nelson Peeler, Jr., and my business address is 525 S. Tryon Street, Charlotte,  
4 North Carolina, 28202.

5 **Q. By whom are you employed and in what capacity?**

6 A. I am the Senior Vice President, Grid Strategy, Planning and Integration for Duke Energy  
7 Corporation (“Duke Energy”).

8 **Q. What are your responsibilities in this role?**

9 A. In this role, I lead the organization responsible for long-term grid planning, including  
10 transmission and renewables planning and integration, transmission planning and  
11 operations strategy, grid solutions development, energy storage development, and strategic  
12 projects. These responsibilities include the planning necessary to support the operational  
13 integration of Duke Energy Carolinas, LLC (“DEC”) and Duke Energy Progress, LLC  
14 (“DEP,” together, with DEC, the “Companies”).

1 **Q. Please briefly summarize your educational background and professional experience.**

2 A. I graduated from North Carolina State University with a Bachelor of Science degree in  
3 Electrical Engineering and earned a Master of Business Administration degree from  
4 Queens University. I am a registered Professional Engineer in both North Carolina and  
5 South Carolina.

6 I have more than 35 years of experience in the energy industry. I joined Duke  
7 Energy in 1988 and have held a variety of leadership positions in power delivery, system  
8 planning and operations, performance support, engineering, construction, business  
9 planning, contract management, process improvement, and training. From 2016 to 2020,  
10 I served as Duke Energy's Chief Transmission Officer. In that role, I oversaw the safe,  
11 reliable, and efficient operation of Duke Energy's electric transmission system. I also  
12 served as Vice President of Transmission System Planning and Operations, where I had  
13 responsibility for real-time monitoring and control of Duke Energy's bulk electric  
14 transmission system. I assumed my current position in 2024.

15 **Q. Please explain the purpose and provide an overview of your testimony.**

16 A. The purpose of my testimony is to support the Companies' application for approval of the  
17 proposed internal corporate reorganization ("Internal Reorganization") in which DEP will  
18 merge with and into DEC, with DEC as the surviving entity. In addition to seeking  
19 approval of the Internal Reorganization from the Federal Energy Regulatory Commission  
20 ("FERC"), the Companies are requesting regulatory approval from the North Carolina  
21 Utilities Commission ("NCUC") and the Public Service Commission of South Carolina  
22 ("PSCSC") in order to consummate the Internal Reorganization on January 1, 2027 ("Legal  
23 Day 1").

1           As a result of the Internal Reorganization, a single electric utility (“Carolinas 1U”)  
2 will serve all existing wholesale and retail customers in the legacy DEC and DEP service  
3 territories. Today, the Companies are separate utilities, even though they are commonly  
4 owned by Duke Energy. As separate utilities, DEC and DEP cannot achieve efficiencies in  
5 planning, execution, and operation because regulatory constraints inhibit their ability to  
6 serve their geographically contiguous service territories as one utility.

7           In my testimony, I explain how the Internal Reorganization is in the public interest  
8 because it will remove the regulatory constraints that inhibit optimal system planning and  
9 allow Carolinas 1U to provide service to its customers in a fully integrated manner, thereby  
10 producing long-term savings and reliability improvements. Specifically, my testimony  
11 provides an overview of the substantial planning, execution, and operational benefits that  
12 will be achieved as a result of the Internal Reorganization. For instance, the Internal  
13 Reorganization will achieve lower overall costs for customers by allowing Carolinas 1U  
14 to:

- 15           • **Plan** investments in necessary generation and transmission resources more  
16           efficiently;
- 17           • **Execute** those plans more efficiently by siting and building those resources  
18           more cost-effectively; and
- 19           • **Operate** those resources more efficiently as a fully integrated system.

20           In summary, and as described in greater detail below, although the amount of actual  
21 savings of the Internal Reorganization will depend on events as they unfold over time, the  
22 savings are estimated to be in the *billions* (anywhere from \$1.6 billion to approximately  
23 \$3.2 billion). As such, the Internal Reorganization is in the public interest because it will

1 result in long-term benefits to all customers by reducing the overall costs to serve as a result  
2 of the planning, execution, and operational efficiencies I discuss below.

3 **II. CUSTOMER BENEFITS: THE INTERNAL REORGANIZATION WILL ALLOW**  
4 **CAROLINAS 1U TO PLAN, EXECUTE, AND OPERATE MORE EFFICIENTLY**

5 **Q. At the outset, please describe your perspective regarding the inherent and intuitive**  
6 **benefits of the Internal Reorganization.**

7 A. As an expert who is deeply familiar with every aspect of the ways in which the Companies  
8 plan and operate their respective systems, I can confidently say that planning for and  
9 operating Carolinas 1U will be in the public interest because it will result in lower costs for  
10 customers on a system basis, as compared to planning for and operating two separate,  
11 smaller utilities. Later in my testimony I explain in detail the planning, execution, and  
12 operational benefits that result from the Internal Reorganization.

13 While the exact magnitude of the benefits will not be known until after the Internal  
14 Reorganization, my conclusion is simply intuitive and plain common sense: overall system  
15 costs will decrease as a result of the efficiencies that Internal Reorganization will bring to  
16 fruition, and customers will benefit from that reduction in overall system costs.

17 **Q. Please provide an overview of the regulatory constraints that currently impact the**  
18 **resource planning and operations of the Companies.**

19 A. In 2012, Duke Energy merged with Progress Energy, Inc. (“Duke/Progress Merger”). Since  
20 the Duke/Progress Merger, the Companies have successfully integrated many of their  
21 functions. For example, the Companies have significantly standardized and consolidated  
22 customer billing, metering and operational systems, and, through operation of the Joint  
23 Dispatch Agreement (“JDA”) approved in connection with the Duke/Progress Merger,  
24 achieved hundreds of millions of dollars in customer savings by jointly dispatching, on a

1 non-firm basis, independently committed resources between DEC and DEP, and sharing in  
2 the resulting production cost savings.

3 But as beneficial as the post-Duke/Progress Merger business integration efforts and  
4 the JDA have been, fundamentally, DEC and DEP remain two *separate* operating utilities.  
5 Regulatory constraints do not permit the Companies to fully and completely function as  
6 one utility. For example, from the resource planning perspective, the Regulatory  
7 Conditions imposed in connection with the NCUC’s approval of the Duke/Progress Merger  
8 require DEC and DEP to separately “pursue least cost integrated resource planning for their  
9 respective Retail Native Load Customers and remain responsible for their own resource  
10 adequacy . . . .”<sup>1</sup> This requirement prohibits the Companies from jointly planning to meet  
11 their combined capacity needs (including projected load forecast and planning reserve  
12 margin), instead forcing DEC and DEP to each separately ensure that each has adequate  
13 resources to independently meet anticipated demand—even where sharing resources would  
14 produce better outcomes for customers. Carolinas 1U will eliminate these barriers and, as  
15 I describe below, ultimately lower costs for customers.

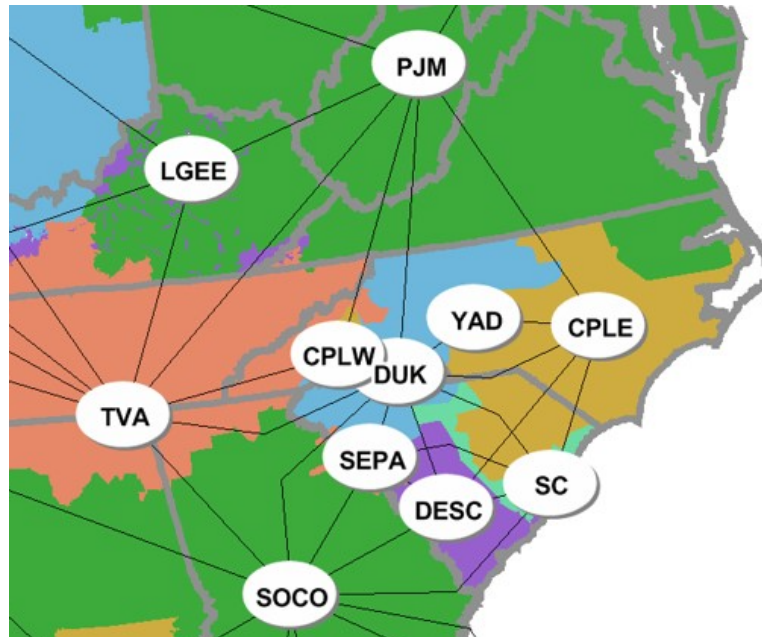
16 Additional constraints result from the fact that DEC and DEP operate as separate  
17 Balancing Authorities for their respective Balancing Authority Area(s) (“BAA”).<sup>2</sup>

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<sup>1</sup> See *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, NCUC Docket Nos. E-2, Sub 998 and E-7, Sub 986, at App. A Regulatory Conditions, Merger Condition 3.5 (June 29, 2012) (“Duke/Progress Merger Order”). Further, the NCUC recently found it appropriate for DEC and DEP to independently model and “independently meet demand and long-term capacity obligations” in its 2024 Integrated Resource Planning Order. *Order Accepting Stipulation, Granting Partial Waiver of Commission Rule R8-60A(d)(4), and Providing Further Direction for Future Planning*, NCUC Docket No. E-100, Sub 190 at 70 (Nov. 1, 2024) (“2024 IRP Order”).

<sup>2</sup> These are North American Electric Reliability Corporation (“NERC”) terms: a “Balancing Authority Area” is a subset of the entire electric grid in which all generation resources are managed to balance power system demand (*i.e.*, load) with supply, and the “Balancing Authority” is the entity responsible for ensuring that that balance is maintained.

1 Currently, as illustrated below, DEC and DEP are responsible for three separate BAAs—  
2 (1) the “DUK” area, corresponding to DEC’s service territory and where DEC is the  
3 Balancing Authority, (2) the “CPLW” area, corresponding to the Asheville area, which is  
4 part of DEP’s service territory, and (3) the “CPL” area<sup>3</sup> corresponding to the balance of  
5 DEP’s service territory. In both the CPLW and CPL E BAAs, DEP is the Balancing  
6 Authority.



7 DEC (as the Balancing Authority for DUK), and DEP (as the Balancing Authority for  
8 CPLW and CPL E), must each must maintain their own real-time load and generation  
9 balance, and independently satisfy NERC reliability standards. These legal and regulatory  
10 constraints preclude the Companies from operating the system holistically. The Internal  
11 Reorganization will collapse the three existing BAAs into one, with Carolinas 1U as the  
12 sole Balancing Authority overseeing a single BAA. As I describe below, the consolidation

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<sup>3</sup> The “CPL” in CPLW and CPL E denotes Carolina Power & Light Company, which is the former name of DEP.

1 into a single BAA will create operational efficiencies that achieve system-wide cost  
2 savings.

3 **Q. With this background information in mind, please provide an overview of the**  
4 **planning and operational benefits of Carolinas 1U.**

5 A. As I mentioned in the Introduction to my testimony, the Internal Reorganization will result  
6 in a single utility (Carolinas 1U), with a single service territory and a single customer base.  
7 The Internal Reorganization will allow Carolinas 1U to plan system resources more  
8 efficiently, execute upon that plan more efficiently, and operate those resources more  
9 efficiently.

10 **A. PLAN**

11 **Q. How will customer benefits result from Carolinas 1U's ability to plan system resources**  
12 **more efficiently?**

13 A. As a single combined utility, Carolinas 1U will be able to plan its investment in generation  
14 and transmission resources more efficiently, resulting in the ability to defer construction  
15 and delay in-service dates of future resources that would have otherwise been needed  
16 earlier if the Companies continued to operate as separate utilities.

17 Today, the regulatory constraints described earlier in my testimony require DEC  
18 and DEP, as separate operating utilities with separate franchised service territories and  
19 BAAs, to each meet their individual capacity needs independently of the other. That is,  
20 each company must have sufficient generation capacity to independently meet its own peak  
21 demand plus a required reserve which, in the case of both Companies, will increase from

1 17% to 22% by 2031.<sup>4</sup> I refer in my testimony to this reserve requirement as a “planning”  
2 reserve margin, as it applies to integrated resource planning.

3 Under Carolinas 1U, the single combined utility will target a combined 22%  
4 planning reserve margin. Additionally, because DEC’s and DEP’s peak usage does not  
5 occur at the same hour on the same day (*i.e.*, it is not perfectly correlated), planning to a  
6 combined system peak results in load diversity and a lower overall peak relative to simply  
7 adding the system peaks of legacy DEC and legacy DEP together. These benefits will  
8 allow Carolinas 1U to defer certain capital investments that otherwise would have to be  
9 built by DEC and/or DEP, operating alone, to meet the increased planning reserve margin  
10 independently by 2031. Deferring these capital investments will result in customer  
11 savings.

12 **Q. Are there other factors that result in greater planning efficiency?**

13 A. Yes. Capacity additions are generally built at standard sizes to take advantage of efficiency  
14 of scope and scale. It is often more efficient to construct a larger resource that satisfies  
15 system capacity needs over several years and then allow demand to grow into that need.  
16 In this way, capacity additions are inherently “lumpy,” and the result of this lumpiness is  
17 that, from time-to-time, utilities have reserve capacity above their planning reserve margin.  
18 By eliminating the need for DEC and DEP to each separately meet their capacity needs,  
19 jointly planning for capacity under Carolinas 1U will allow for the integration of resources  
20 to reduce the periods of excess capacity. Reducing lumpiness results in reduced cost, and  
21 reducing the cost of carrying excess capacity while maintaining reliability is a clear benefit  
22 to customers.

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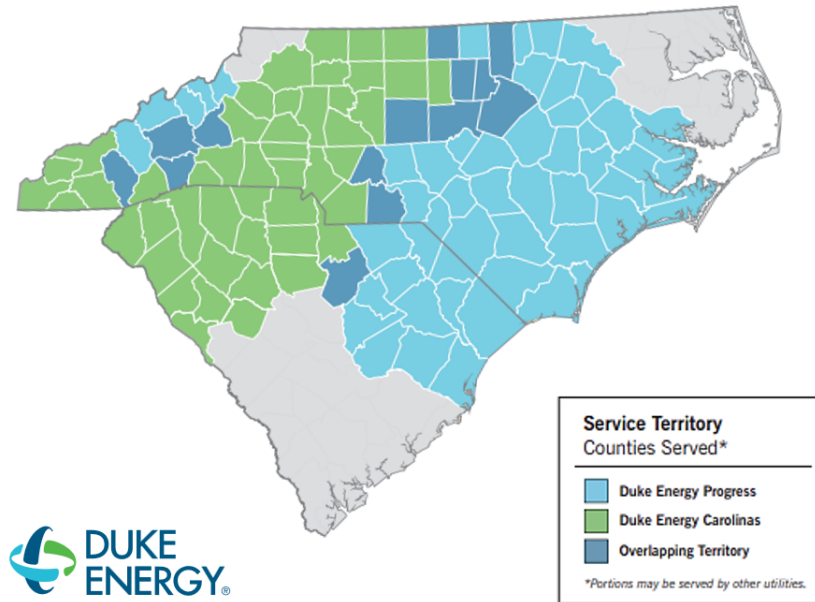
<sup>4</sup> See 2024 IRP Order at 49 (finding a 22% planning reserve margin to be “reasonable for planning purposes”).

**B. EXECUTE**

**Q. How will the Internal Reorganization result in Carolinas 1U being able to execute its system resource planning more efficiently?**

A. Geographic differences between the legacy DEC and legacy DEP service territories make each legacy service territory more optimal for siting and building certain types of generation resources than the other. As shown in the territory map reproduced below, legacy DEC’s service territory covers the western parts of the Carolinas, including portions of the Blue Ridge Mountains and foothills, and the heavily populated Piedmont region east of the mountains. In contrast, legacy DEP’s service territory mostly covers the eastern parts of the Carolinas toward the coast, with a relatively small pocket of territory in the west along the Tennessee border and around Asheville.

**Carolinas Service Territory**



Accordingly, DEC’s service territory is, in general, hillier and more wooded, whereas DEP’s service territory, apart from the Western North Carolina region, is generally more coastal and flatter, with fewer wooded areas and less cloud cover. These geographic

1 differences are the main drivers of each legacy service territory's suitability for the  
2 development of different generation resources. For example, pumped storage is more  
3 suited to DEC's service territory due to its mountainous terrain. Conversely, building  
4 utility scale solar generation requires areas of flat, open land, and is better suited to DEP's  
5 current service territory. Similarly, onshore wind generation is also better suited to DEP's  
6 territory, with its coastal wind resources, particularly as onshore wind in the mountains is  
7 constrained by the legal limitations imposed by North Carolina's Mountain Ridge  
8 Protection Act.

9 Further, in order to meet its own energy needs absent the Internal Reorganization,  
10 DEC's separate resource plan would be required to site and build its own proportionate  
11 amount of solar generation, at a higher cost to DEC customers than if that resource were to  
12 be developed by Carolinas 1U with siting decisions optimized across the entire single  
13 utility footprint.

14 In summary, the Internal Reorganization will benefit all customers by allowing  
15 Carolinas 1U to capitalize on the advantages of the varying geographies of the legacy DEC  
16 and DEP service territories in an optimal manner, matching the generation need with the  
17 corresponding favorable geography. Simply put, the creation of a single utility—Carolinas  
18 1U—eliminates geographic barriers that would otherwise serve to increase customer costs.

19 **Q. Are there other factors that bear upon optimal execution of resource siting and**  
20 **building decisions?**

21 A. Yes. Access to existing infrastructure is another factor. For example, existing natural gas  
22 pipelines run through western North Carolina in DEC's current service territory, which  
23 means that it will often be more cost effective to site and develop natural gas generation

1 resources in that territory. Indeed, without the Internal Reorganization, the cost of siting  
2 additional natural gas plants in DEP's service territory over and above the two combined  
3 cycle plants currently planned for that territory would generally be higher due to the need  
4 to build additional pipeline infrastructure to support any future additional plants.

5 In sum, Carolinas 1U will allow the single combined utility resulting from the  
6 Internal Reorganization to site and build resources more cost-effectively, taking advantage  
7 of favorable geographic and infrastructure realities and without regard to existing  
8 constraints attendant upon the need to ensure that legacy DEC and legacy DEP each have  
9 adequate resources to meet anticipated demand.

10 **Q. Do additional customer benefits result from Carolinas 1U's ability to optimally**  
11 **execute upon its resource planning?**

12 A. Yes. A larger utility with a larger customer base is better able to bear the capital costs  
13 associated with developing generation when it is required, including large-scale resources  
14 such as new nuclear generation. Investments, whether large-scale or not, that are made in  
15 Carolinas 1U will be spread over a larger customer base, which moderates the resulting  
16 customer rate impact.

### 17 C. OPERATE

18 **Q. How will the Internal Reorganization allow Carolinas 1U to operate its combined**  
19 **system resources more efficiently?**

20 A. Carolinas 1U will consolidate the three existing DEC and DEP BAAs into a single BAA,  
21 and that single BAA will create operational efficiencies that result in substantial system-  
22 wide cost savings. As I discussed earlier in my testimony, DEC and DEP currently face

1 regulatory constraints that prohibit the Companies from fully leveraging the benefit of  
2 operating with the efficiencies of a single combined utility.

3 In their current operations, DEC and DEP must each meet their own operating  
4 requirements with their own resources within their individual BAAs. By contrast, a  
5 combined utility operating a single BAA would be able to commit its (then) jointly held  
6 resources to meet the combined system's operational requirements. Stated differently,  
7 although under the JDA the Companies may, under certain circumstances, *dispatch* their  
8 generation resources to assist with each other's operational needs, DEC and DEP may not  
9 *commit* their generation resources to each other to meet the other utility's system  
10 operational needs.

11 **Q. Please explain the difference between unit commitment and unit dispatch.**

12 A. Unit commitment are operational decisions a utility must make regarding which generating  
13 units to turn on (commit) or off (decommit) in preparation to meet system demand. Unit  
14 dispatch refers to near real-time decisions regarding how much generation should be  
15 produced by generating units. Under current regulatory constraints, DEC and DEP are not  
16 permitted to make joint unit commitment decisions but are permitted to make joint dispatch  
17 decisions (as facilitated by the JDA).<sup>5</sup>

18 The primary difference is in the operative time horizon. Dispatching resources is  
19 generally conducted within a day as utility operators meet real-time demand. On the other  
20 hand, commitment/decommitment involves the starting or shutting down of resources.

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<sup>5</sup> The testimony of witness Ellis discusses how the Companies are parties to an "As-Available Capacity Sales Agreement" on file with FERC, and how this agreement permits the Companies, under very limited circumstances, and subject to pre-defined conditions, to purchase short-term capacity from one another, but does not permit joint unit commitment.

1 Commitment plans are assessed over a longer, although still near-term, time horizon—  
2 typically one to ten days.

3 **Q. Are the operational benefits of joint unit commitment distinct from the benefits of**  
4 **joint capacity planning?**

5 A. Yes. The benefits of joint unit commitment are distinct from but analogous to the benefits  
6 of joint capacity planning. In the same way that the Internal Reorganization benefits all  
7 customers by allowing for joint resource planning for purposes of *planning* reserve margin,  
8 the Internal Reorganization also allows for joint commitment for purposes of *operating*  
9 reserve margin.

10 **Q. How will the Internal Reorganization facilitate more efficient unit commitment?**

11 A. Operating under their current regulatory constraints, the Companies must independently  
12 ensure that they have adequate resource availability to meet expected load (that is,  
13 sufficient unit commitment). While the JDA facilitates *joint dispatch* to meet the  
14 Companies' intraday loads on the most cost-effective basis, the JDA does not allow *joint*  
15 *unit commitment*.

16 The Internal Reorganization will result in a one utility operating as a single  
17 Balancing Authority that will be able to jointly commit all resources of legacy DEC and  
18 legacy DEP in its BAA to more efficiently meet the needs of the larger footprint. In  
19 practical terms, what this means is that Carolinas 1U will have access to the entire fleet of  
20 legacy DEC and DEP resources for purposes of unit commitment and can therefore ensure  
21 that the lowest cost resources on the system are being committed, resulting in overall  
22 system cost savings, including lower fuel costs.

1 **Q. What is an operating reserve margin and how does it relate to unit commitment?**

2 A. Under NERC standards, the Balancing Authority is required to meet the energy demands  
3 of its customers in the Balancing Authority Area it oversees. In order to meet that demand  
4 reliably, the Balancing Authority needs to maintain an operating reserve margin over and  
5 above firm system demand. The operating reserve is maintained to handle uncertainties  
6 and for compliance with NERC standards. Operating reserve must be sufficient to respond  
7 to the “most severe single contingency,” which, for both DEC and DEP, is the loss of the  
8 system’s largest resource. The operating reserve must also be sufficient to provide a  
9 regulating reserve and to provide a buffer in case of load forecasting error. The unit  
10 commitment decisions that a utility makes help the utility to maintain a sufficient operating  
11 reserve margin.

12 Similar to the planning reserve margins efficiencies, the Internal Reorganization  
13 will result in the elimination of duplicative operating reserve margin requirements,  
14 allowing for unit commitment decisions to be made in the most efficient manner across a  
15 single system. The single operating reserve margin will result in savings of hundreds of  
16 megawatts (“MW”) of otherwise-required operating reserves, which will translate into  
17 customer savings.

18 **Q. You mentioned that the planning for loss of the system’s largest resource is one aspect  
19 of operating reserve. Please explain further.**

20 A. Currently, as separate Balancing Authorities, DEC and DEP must meet the energy demands  
21 of their separate Balancing Authorities, including their separate operating reserve margins.  
22 Each Balancing Authority must prepare a next day “operating plan” to ensure reliable  
23 system operation.

1 Under the Companies' operating plans, each must have a strategy for replacing the  
2 loss of their respective largest generation resources. For DEC, that resource is McGuire  
3 Unit 1, at 1199 MW; for DEP, that resource is Harris Unit 1, at 1009 MW. Today, DEC  
4 and DEP each separately plan for the loss of the applicable resource and determines where  
5 and how their operators can secure alternative power to make up for the lost generation.  
6 Under Carolinas 1U, by contrast, the sole Balancing Authority over the combined BAA  
7 need only plan for the loss of McGuire Unit 1, effectively allowing a larger, more diverse  
8 system to plan for the potential loss of a smaller proportion of its overall operating capacity.

9 **Q. You mentioned that regulating reserve is another aspect of operating reserve. Please**  
10 **explain further.**

11 A. Regulating reserve is another component in developing the operating plan. Regulating  
12 reserve is necessary because changes in power supply and demand cannot be predicted  
13 precisely, so the regulating reserve helps the Balancing Authority match (within a certain  
14 tolerance range) the bandwidth of generation and load at all times. Regulating reserve is  
15 maintained in real-time by units already online and with an ability to respond to control  
16 signals to adjust their output.

17 Currently, DEC and DEP must each maintain separate regulating reserves, whereas  
18 under Carolinas 1U, the combined utility will only need to maintain a single reserve. With  
19 a broader footprint and larger array of generation resources, Carolinas 1U will be able to  
20 meet the single regulating reserve with fewer or cheaper units, use less fuel, and reduce  
21 unit cycling, thus saving on operations and maintenance costs.

1 **Q. You mentioned that load forecast error is another aspect of operating reserve. Please**  
2 **explain further.**

3 A. As utility operators plan for each day, they must forecast what the load will be and,  
4 therefore, accounting for potential forecast error is a component in developing the  
5 operating plan and operating reserve margin targets. All calculations are subject to error.  
6 Today, two forecasts, involving two sets of calculations, are prepared by DEC and DEP  
7 separately. Carolinas 1U will produce a single forecast for the single utility. Statistically,  
8 a single calculation has greater accuracy than two separate calculations, so the single  
9 Carolinas 1U calculation of forecast error will be more accurate and, over time, reduce the  
10 forecast error component of operating reserve margin.

11 **Q. Please summarize the operational benefits of the Internal Reorganization.**

12 A. All of the operational efficiencies discussed above result in customer savings through  
13 reduced fuel usage, reduced maintenance costs due to reducing unit cycling, reduced off-  
14 system reliability purchases, and reduced solar curtailment.<sup>6</sup>

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<sup>6</sup> A Balancing Authority may not produce power that it cannot use without going out of balance. As load (demand) drops during the day, operators take units offline so as to maintain the required balance. However, in order to meet reliability standards, utility operators are limited in how many units they can take offline during a valley period in order to be ready to ramp up as a peak period approaches. Operators may not remove units from operation below this minimum even though demand may be theoretically low enough to warrant such removal. If the utility faces a situation in which it must maintain generation online even though the demand is not there — *i.e.*, if the utility is over-generating—it must either sell the excess power, sometimes at a loss, or it must curtail generation. Solar generation has zero fuel cost, so it is often advantageous to maximize its usage, but the balancing requirements embedded in NERC standards sometimes do not permit the utility to keep available solar generation online. Carolinas 1U will be able to reduce solar curtailment because a larger utility, with a larger footprint, is better able to spread the load requirement.

1                   **D. CONCLUSION AS TO PLANNING, EXECUTION, AND OPERATIONAL**  
2                   **BENEFITS**

3 **Q. Taking a step back from the details, what are the biggest takeaways from the**  
4 **planning, execution, and operational benefits you described?**

5 A. The Internal Reorganization will allow Carolinas 1U to plan, execute, and operate its  
6 system as a single utility, removing barriers that currently prevent the Companies from  
7 fulfilling what is, at bottom, a practical and straightforward goal: running a fully integrated  
8 system. These improvements will reduce redundancy, support more strategic and cost-  
9 effective planning, and allow the system to operate with greater efficiency and flexibility.  
10 The Internal Reorganization will not only lower overall system costs but it also  
11 incorporates solutions that common sense indicates will produce customer savings.

12 **Q. Have DEC and DEP estimated the potential savings associated with the Internal**  
13 **Reorganization?**

14 A. Yes. The Companies project that savings will be in the *billions* of dollars—anywhere from  
15 approximately \$1.6 billion in potential savings for the system to approximately \$3.2 billion  
16 in potential savings.

17                   **III. CONCLUSION**

18 **Q. Please summarize your testimony.**

19 A. The Internal Reorganization will allow Carolinas 1U to plan, execute, and operate as a fully  
20 integrated single utility, resulting in savings that will be in the *billions* of dollars. Carolinas  
21 1U will enable optimized resource siting. As a combined utility, Carolinas 1U will not be  
22 bound by legacy utility service territories and will be able to site resources—such as  
23 nuclear, natural gas, solar, wind, and hydro pumped storage—based on where the resource  
24 is most cost-effective system-wide. Further, the Internal Reorganization will facilitate the

1 creation of a consolidated Balancing Authority, permitting Carolinas 1U to jointly commit  
2 generation resources across DEC and DEP instead of each utility having to independently  
3 ensure its own resource availability, and allowing for a single planning reserve margin.  
4 The ability to jointly plan will provide Carolinas 1U the flexibility to enable more efficient,  
5 system-wide capital deployment, resulting in lower long-term system costs for customers.  
6 As these examples highlight, the ability to plan, execute and operate as a combined utility  
7 will reduce overall costs and help maintain affordable rates for customers.

8 I am therefore confident in my expert opinion that the Internal Reorganization is in  
9 the public interest because the substantial long-term benefits provided to all customers in  
10 the form of reduced system cost of service and customer savings generated by the system  
11 planning, execution, and operational efficiencies.

12 **Q. Does this conclude your testimony?**

13 **A. Yes.**

UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION

Duke Energy Corporation )  
Duke Energy Carolinas, LLC ) Docket No. EC25-\_\_\_-000  
Duke Energy Progress, LLC )

PREPARED DIRECT TESTIMONY OF NELSON PEELER

VERIFICATION

State of North Carolina )  
)

I, V. Nelson Peeler, Jr., being first duly sworn, state that I am the witness identified in the foregoing prepared testimony, and that the statements of fact in the testimony are true and correct to the best of my knowledge, information, and belief.



V. Nelson Peeler, Jr.

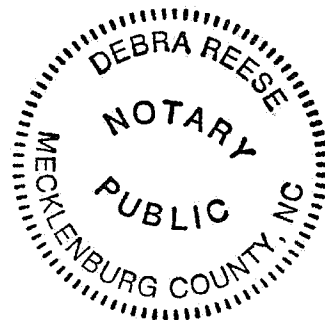
SUBSCRIBED AND SWORN before me

the 6 day of August, 2025

Debra Reese Debra Reese  
Notary Public



My commission expires on: October 7, 2025



**Attachment 2**

**Prepared Direct Testimony of Jennifer S. Ellis**

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

**Duke Energy Corporation** )  
**Duke Energy Carolinas, LLC** ) **Docket No. EC25-\_\_\_\_-000**  
**Duke Energy Progress, LLC** )

**PREPARED DIRECT TESTIMONY OF  
JENNIFER S. ELLIS  
ON BEHALF OF  
DUKE ENERGY CORPORATION,  
DUKE ENERGY CAROLINAS, LLC AND  
DUKE ENERGY PROGRESS, LLC**

**August 14, 2025**

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

<b>Duke Energy Corporation</b>	)	
<b>Duke Energy Carolinas, LLC</b>	)	<b>Docket No. EC25-____-000</b>
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**I.     INTRODUCTION**

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**Q.     Please state your name and business address.**

A.     I am Jennifer S. Ellis. My business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

**Q.     By whom are you employed and in what capacity?**

A.     I am employed by Duke Energy Progress, LLC (“DEP”) as General Manager of Wholesale Sales.

**Q.     Please briefly describe your educational background and employment history.**

A.     I received a Bachelor of Science degree in Accounting from Mars Hill College in 1992, and I am a Certified Public Accountant licensed in the State of North Carolina. From 1992 to 1999, I was employed in the banking industry as a Commissioned Financial Institution Examiner with the Federal Deposit Insurance Corporation and then as Vice President & Internal Auditor for Four Oaks Bank & Trust Company. From 1999 through 2001, I was employed by Nortel Networks, Inc., as a Senior Financial Analyst. I joined Progress Energy in late 2001 as a Senior Business Financial Analyst. I was promoted to manager in

1 2003. After joining Progress Energy, Inc. (“Progress Energy”), I held various management  
2 positions within the accounting department in the areas of unregulated power plants,  
3 wholesale power sales, fuel, and Assistant Controller of the Progress Energy Service  
4 Company. In 2008, I joined the wholesale power department as Manager, Wholesale  
5 Power-Progress Energy Carolinas, Inc. In August of 2012, following the merger between  
6 Progress Energy and Duke Energy Corporation, I accepted the position of Manager,  
7 Carolinas Wholesale. In early 2014, my title was changed to Director, Carolinas  
8 Wholesale. I was promoted to my current position in 2020.

9 **Q. Please describe your duties and responsibilities as General Manager of Wholesale**  
10 **Sales at DEP.**

11 A. In this role, I lead the groups responsible for all commercial activities associated with the  
12 long-term sale of capacity and energy to wholesale customers, as well as the activities  
13 associated with joint ownership of any regulated assets. These responsibilities include  
14 overseeing the origination, negotiation and account management functions for wholesale  
15 power sales and joint ownership contract for all of Duke’s regulated entities.

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

17 A. My testimony provides an overview of the wholesale power supply business of DEP and  
18 Duke Energy Carolinas, LLC (“DEC,” together with DEP, “the Companies”) and discusses  
19 the benefits and impacts of the proposed internal corporate reorganization in which DEP  
20 will be merged into DEC, with DEC as the surviving entity (the “Internal Reorganization”).  
21 If approved, the Internal Reorganization will result in a single electric utility (“Carolinas  
22 1U”).

1 My testimony also explains the “Share the Benefits Plan,” a component of the  
2 Companies’ rate mitigation plan (“1U Rate Mitigation Plan”), that involves a five-year  
3 deferral of merger savings by existing DEP wholesale customers in order to share those  
4 savings with South Carolina retail customers and fund credits to current DEC wholesale  
5 power supply customers to offset cost reallocations resulting from the Internal  
6 Reorganization. The 1U Rate Mitigation Plan consists of two components: (1) the Share  
7 the Benefits Plan; and (2) the OATT Mitigation Plan. Witness Blain Atkins’ testimony  
8 discusses how the Internal Reorganization impacts the Companies’ Joint OATT customers  
9 and provides an overview of the Companies’ proposed three-part OATT Mitigation Plan.

10 Because approval of the Internal Reorganization is required from all three  
11 jurisdictions in which the Companies operate—the Federal Energy Regulatory Commission  
12 (“FERC”), the North Carolina Utilities Commission and the Public Service Commission  
13 of South Carolina – the Share the Benefits Plan plays a critical role in demonstrating that  
14 the Internal Reorganization will provide both near- and long-term system benefits to all  
15 customers.

16 **Q. How would you summarize the impact of the Internal Reorganization on the**  
17 **Companies’ wholesale power supply customers?**

18 A. The Internal Reorganization is being pursued for the various long-term benefits it will  
19 provide to all DEC and DEP customers. Witness Nelson Peeler discusses how the  
20 Companies have identified quantitative and qualitative long-term benefits for customers,  
21 including operational efficiencies and the ability to make more efficient generating  
22 capacity investment decisions, resulting in sizeable system level savings. My testimony is  
23 focused on how the Internal Reorganization will impact the existing wholesale power

1 supply customers of legacy DEC and DEP through their formula rates, and specifically,  
2 how the Share the Benefits Plan will provide rate mitigating measures to the Companies'  
3 existing wholesale power supply customers.

4 As is the case with most mergers of vertically integrated utilities, certain rate  
5 equalization (or averaging) effects resulting from combining two entities' rate structures  
6 would, if left unaddressed, result in a rate increase for customers of the lower-cost legacy  
7 system and an immediate rate decrease for customers of the higher cost system. In this  
8 instance, DEC's wholesale power supply customers currently enjoy lower rates than DEP's  
9 wholesale power supply customers largely because DEC has a larger customer base and  
10 less expensive generating resources as compared to DEP.<sup>1</sup> Therefore, absent the Share the  
11 Benefits Plan, legacy DEC wholesale power supply customers would experience increased  
12 rates following the Internal Reorganization and legacy DEP wholesale power supply  
13 customers would experience decreased rates. I refer to this phenomenon as the  
14 "Equalization Effect," and my testimony addresses the Equalization Effect as it applies to  
15 the Companies' wholesale power supply rates.<sup>2</sup> I also explain more fully below how the  
16 Share the Benefits Plan addresses the rate impacts in the short term on DEC's existing

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<sup>1</sup> As explained in witness Peeler's testimony, geographic differences between the service territories of legacy DEC and legacy DEP make each legacy service territory more optimal for siting and building certain types of generation resources than the other. For instance, DEC's service territory covers the western parts of North and South Carolina, including portions of the Blue Ridge Mountains and foothills, and a heavily populated region east of the mountains. In contrast, DEP's service territory mostly covers the eastern/coastal parts of the Carolinas and includes a relatively small pocket of territory in the west in and around Asheville. Since DEC's territory is, in general, hillier and more wooded, pumped storage is more suited to DEC's service territory whereas DEP's territory, which is generally flat and coastal, has fewer wooded areas, and experiences less cloud cover, is more suitable for utility scale solar generation and onshore wind. Additionally, DEC is closer to fuel sources, which results in lower fuel costs, and it has more nuclear capacity.

<sup>2</sup> Witness Atkins also addresses the Equalization Effect, but her testimony focusses on its application to the Companies' Joint OATT rates.

1 wholesale power supply customers and better positions the legacy customers of both  
2 Companies to benefit from the Internal Reorganization in the long run.

3 **II. THE COMPANIES' WHOLESALE POWER SUPPLY BUSINESS AND**  
4 **CURRENT OPERATIONS**

5 **Q. Please summarize the wholesale power supply business of the Companies.**

6 A. Like many large investor-owned utilities, in addition to providing retail service, the  
7 Companies provide wholesale power supply under long-term bilaterally negotiated  
8 contracts to several electric cooperatives, municipal utilities, and other entities with retail  
9 service obligations in the Carolinas.

10 **Q. Who are the Companies' current wholesale power supply customers?**

11 A. DEC currently has active wholesale power supply contracts with twelve customers<sup>3</sup> and  
12 DEP currently has active wholesale power supply contracts with six customers.<sup>4</sup>

13 **Q. Do the Companies engage in joint planning to ensure their systems can meet the needs**  
14 **of their respective wholesale customers?**

15 A. No. DEC and DEP currently operate and function as two separate utilities because  
16 regulatory constraints do not permit the Companies to fully and completely function as one  
17 utility.

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<sup>3</sup> DEC's current wholesale power supply customers are: Blue Ridge Electric Membership Corporation ("BREMC"); Rutherford Electric Membership Corporation ("REMC"); Haywood Electric Membership Corporation ("HEMC"); Central Electric Power Cooperative, Inc. ("Central"); City of Orangeburg, South Carolina ("Orangeburg"); Lockhart Power Company ("Lockhart"); Town of Dallas, North Carolina ("Dallas"); Town of Due West, South Carolina ("Due West"); Town of Forest City, North Carolina ("Forest City"); Town of Highlands, North Carolina ("Highlands"); North Carolina Electric Membership Corporation ("NCEMC"), and Piedmont Electric Membership Corporation ("Piedmont").

<sup>4</sup> DEP's current wholesale power supply customers are HEMC; Fayetteville Public Works Commission ("FPWC"); French Broad Electric Membership Cooperative ("FBEMC"); North Carolina Eastern Municipal Power Agency ("NCEMPA"); NCEMC; and Piedmont.

1 **Q. Please explain further.**

2 A. As explained in greater detail in witness Peeler's testimony, under current regulatory  
3 constraints, DEP and DEC are not permitted to make joint planning decisions. As two  
4 separate utilities, the Companies must plan for and make capital investment decisions  
5 separately because each utility must independently ensure that it has adequate resource  
6 availability to meet the expected load of its retail and wholesale customers.

7 **Q. What is the Joint Dispatch Agreement ("JDA") between the Companies?**

8 A. As described in detail in witness Peeler's testimony, DEC and DEP are parties to a JDA  
9 that entitles the Companies to jointly dispatch, on a non-firm basis, independently  
10 committed resources and share in the production cost savings. The JDA, however, only  
11 provides the Companies with the ability to share energy (not capacity) if transmission  
12 capacity is available across the boundaries of their currently separate Balancing Authority  
13 Areas.<sup>5</sup> Therefore, although the JDA permits the Companies to achieve dispatch savings  
14 by supplying each other with energy intraday when, for example, DEC or DEP can make a  
15 sale to the other out of a resource that is cheaper than buying the next cheapest deliverable  
16 resource, it does not allow the Companies to jointly commit units or to re-allocate the fixed  
17 costs of capacity between DEC and DEP. Accordingly, the Companies must independently  
18 consider the load growth of their respective retail and wholesale power supply customers

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<sup>5</sup> The Companies are also parties to an "As-Available Capacity Sales Agreement" on file with FERC. This agreement permits the Companies, under very limited circumstances, and subject to pre-defined conditions, to purchase capacity from one another. Specifically, the Companies can sell each other short-term capacity when: either DEC or DEP has excess capacity, either DEC or DEP (as the entity receiving the capacity) would benefit from the acquisition of such capacity, and no economical short-term capacity supply alternatives are available from other sellers. If those conditions are met, then the Companies may transact for short-term capacity of not less than four (4) consecutive hours and not more than twenty-three (23) consecutive hours. In short, this arrangement, while helpful, does not allow for joint unit commitment in the way that the Internal Reorganization would allow.

1 when making resource planning decisions, and DEC and DEP must each submit their own  
2 integrated resource plans, which are separately evaluated and approved by the North  
3 Carolina Utilities Commission and the Public Service Commission of South Carolina.

4 **Q. Are these limitations a major driver of the Internal Reorganization?**

5 A. Yes. Witness Peeler discusses the current regulatory constraints in his testimony and  
6 explains that Carolinas 1U will unlock planning, execution, and operational efficiencies  
7 thereby delivering customer savings.

8 **Q. Witness Peeler discusses savings in terms of deferring certain capacity investments**  
9 **that would otherwise be necessary if the Companies continued to operate as separate**  
10 **utilities because Carolinas 1U will be able to take advantage of the geographic**  
11 **diversity of the legacy DEC and legacy DEP service territories in making capacity**  
12 **procurement decisions that will be more efficient in the long run. Will those benefits**  
13 **accrue to the benefit of DEC and DEP wholesale power supply customers as well?**

14 A. Yes. The Companies' retail and wholesale power supply customers contribute to fixed  
15 capacity costs of the system. Therefore, any savings generated by delaying or avoiding  
16 capacity investments will reduce the costs otherwise paid by DEC and DEP's wholesale  
17 power supply customers.

18 **III. IMPACT OF THE INTERNAL REORGANIZATION ON THE COMPANIES'**  
19 **WHOLESALE POWER SUPPLY RATES**

20 **Q. Please summarize how the Companies' wholesale power supply rates are calculated.**

21 A. Each of the Companies' wholesale power supply contracts are cost-based agreements on  
22 file with FERC. The contracts contain formula rates that include both the fixed and variable  
23 costs of either DEC or DEP.

1 **Q. How do the wholesale power supply rates for the Companies compare today?**

2 A. Due to DEP's resource mix, the geography of its service territory, and various other factors  
3 I previously discussed, DEP's wholesale formula rates are higher than those paid by DEC  
4 wholesale power supply customers. These factors also result in generally higher rates for  
5 DEP retail customers as compared to DEC retail customers.

6 **Q. How will wholesale rates be calculated for Carolinas 1U?**

7 A. Merging DEC and DEP will create a single utility (Carolinas 1U) that calculates rates for  
8 wholesale power supply service and transmission service. Effective January 1, 2027  
9 ("Legal Day 1"), the Companies' current wholesale customers will begin to take service  
10 from Carolinas 1U and Carolinas 1U will produce a single FERC Form 1. As such, each  
11 of the Companies' wholesale power supply customers' formula rate templates will be  
12 populated with the cost inputs of Carolinas 1U. Specifically, the numerator of the  
13 wholesale power supply rates will be based on the combined cost of service of the newly-  
14 merged utility (Carolinas 1U). Similarly, the denominator of these rates will be the  
15 combined demand of the legacy DEC and legacy DEP customers.

16 **Q. What effect will the Internal Reorganization have on wholesale power supply rates  
17 for Carolinas 1U?**

18 A. As with all mergers that result in combining rate structures, it is inevitable that there will  
19 be some degree of an "Equalization Effect" as a result of the Internal Reorganization such  
20 that Carolinas 1U's wholesale rates will be comparatively lower than the rates that DEP's  
21 wholesale power supply customers pay today, and comparatively higher than the rates that  
22 DEC's wholesale power supply customers pay today.

1 **Q. What about impacts to the Companies' retail jurisdictions?**

2 A. Combining the Companies' wholesale cost of service calculations impacts more than just  
3 wholesale power rates. Today, the wholesale jurisdiction represents a larger share of the  
4 DEP system (the higher-cost system) than the DEC system, and the South Carolina retail  
5 jurisdiction currently represents a larger share of the DEC system (the lower-cost system).  
6 The North Carolina retail jurisdiction currently has a more balanced share across the DEC  
7 and DEP systems, with a slightly higher share of the DEC system. After the Internal  
8 Reorganization, under a single cost of service, there will necessarily be changes in the  
9 outcomes at the jurisdictional level (wholesale vs. retail) resulting from the cost-of-service  
10 allocation of the combined system. This is a natural outcome resulting from the facts noted  
11 above, namely: (a) the costs of the Companies' existing systems are not identical, and (b)  
12 the jurisdictional shares of the Companies' existing systems are not identical.

13 Thus, the impact of the Internal Reorganization is that costs will initially shift *away*  
14 from the wholesale jurisdiction and *to* the retail jurisdictions, with the South Carolina retail  
15 jurisdiction bearing a greater impact because South Carolina retail will receive a larger cost  
16 of service allocation of the higher-cost DEP system than was the case before the Internal  
17 Reorganization. Specifically, the Share the Benefits Plan dedicates a portion of the  
18 contributions from current DEP wholesale power supply customers to South Carolina retail  
19 customers for the transition period.



1 **Q. Please provide more information about the Share the Benefits Plan and how it was**  
2 **developed.**

3 A. At a high level, the Share the Benefits Plan smooths the transition to Carolinas 1U by  
4 mitigating near-term impacts. The Share the Benefits Plan has two distinct objectives.  
5 First, it addresses the Equalization Effect that would otherwise result in an immediate rate  
6 increase for existing DEC wholesale power supply customers and a corresponding rate  
7 decrease for DEP's current wholesale power supply customers. To mitigate the rate impact  
8 to current DEC wholesale customers, the Share the Benefits Plan is designed with the goal  
9 of achieving a reasonable proxy for rate neutrality over a five-year transitional period to  
10 protect DEC's existing wholesale power supply customers from paying more after the  
11 Internal Reorganization than before, and allow time for customers to start benefitting from  
12 the deferred capital investments and other long-term planning efficiencies that will be  
13 achieved by the Internal Reorganization. Since the immediate net beneficiaries of the  
14 Internal Reorganization are DEP's existing wholesale power supply customers, the Share  
15 the Benefits Plan asks those customers to temporarily delay the otherwise immediate cost-  
16 shift benefits by paying charges based on the costs of the legacy DEP system, thereby  
17 reasonably maintaining rate neutrality for existing DEP wholesale power supply customers.

18 Second, the Share the Benefits Plan is designed to mitigate the near-term impact of  
19 the cost reallocation to the South Carolina retail jurisdiction by allocating a portion of the  
20 DEP wholesale contributions to the South Carolina retail jurisdiction.

21 **Q. You mentioned that DEP's wholesale power supply customers are being asked to**  
22 **agree to the Share the Benefits Plan by delaying receipt of their otherwise immediate**  
23 **cost-shift benefits. What specifically does that mean?**

1 A. On Legal Day 1, Carolinas 1U will have one set of books, and ultimately a single FERC  
2 Form 1. Each wholesale power supply customer of legacy DEC and legacy DEP will take  
3 service under formula rate templates that will be populated with a single set of cost impacts.  
4 Consequently, without an intervening mitigation plan, the Equalization Effects I described  
5 above will occur.

6 In order to “mimic” the current cost allocation, with the goal of achieving rate  
7 neutrality for legacy DEC and legacy DEP wholesale power supply customers during the  
8 five-year transition period, we are requesting that DEP’s wholesale power supply  
9 customers agree to a fixed monthly “adder” for a five-year period. While I refer to this as  
10 an *adder*—because that is how it must be implemented—the better way to view this rate  
11 mitigation tool is that it is a means for DEP’s wholesale power supply customers to help  
12 smooth the immediate effects of the Internal Reorganization on DEC’s wholesale power  
13 supply customers and offset the near-term impacts of the cost reallocation to the South  
14 Carolina retail customers. For a five-year transitional period, this requires legacy DEP  
15 wholesale power supply customers to continue paying charges based on today’s cost  
16 allocation and therefore forego the immediate cost-shift benefits associated with the  
17 Internal Reorganization. Viewed differently, the “adder” maintains the costs DEP’s  
18 wholesale power supply customers would otherwise have paid for the legacy DEP system  
19 absent the Internal Reorganization.

20 **Q. What methodology did the Companies use to determine the amount to be collected**  
21 **from DEP’s wholesale power supply customers over the five-year transitional period?**

22 A. In developing the Share the Benefits Plan, the Companies first analyzed what DEP’s  
23 wholesale power supply customers would have paid under a combined utility scenario,

1 versus their actual payments as stand-alone legacy DEP customers, over a three-year  
2 lookback period. The average of these analyses determined that without rate mitigation,  
3 DEP's wholesale power supply customers would be expected to pay an average of \$88  
4 million less per year in the aggregate as a customer class upon closing the Internal  
5 Reorganization.

6 This analysis established the amount that the Companies worked from in  
7 developing a mitigation plan for DEC's current wholesale power supply customers and  
8 South Carolina retail customers. Relying on this analysis, the Share the Benefits Plan  
9 contemplates that DEP's wholesale power supply customers continue to pay their current  
10 proportionate share of DEP's legacy system costs for a limited duration, and delay paying  
11 the lower Carolinas 1U rate. In dollar amounts, the Share the Benefits Plan proposes that  
12 DEP's wholesale power supply customers contribute an average of \$88 million per year to  
13 assist with rate mitigation efforts for DEC's wholesale power supply customers and to  
14 offset the cost reallocation impacts to South Carolina retail customers.

15 **Q. How did the Companies calculate the rates to be paid by each DEP wholesale power**  
16 **supply customer?**

17 A. The Companies took the delta between the average of what DEP wholesale power supply  
18 customers actually paid over the three-year lookback period noted above and what they  
19 would have paid if the Companies had been combined during those periods to determine  
20 the mitigation amounts. The analyses added together the actual revenue requirements for  
21 legacy DEP and legacy DEC and the formula rate denominators for legacy DEP and legacy  
22 DEC as the basis for Carolinas 1U rates. These rates were then applied to each customer's  
23 demand and energy consumptions to calculate their total costs on a combined utility basis.

1 The average delta between each DEP wholesale power supply customer's actual costs and  
2 their costs under a Carolinas 1U scenario provided a fixed cost shift number (the  
3 "Reorganization Amount") reflecting the immediate financial benefit each customer would  
4 receive by combining the Companies' existing systems.

5 **Q. Have all of DEP's wholesale power supply customers agreed to the Reorganization**  
6 **Amount for a five-year period?**

7 A. Each DEP wholesale power supply customer has indicated an agreement in principle to  
8 include the Reorganization Amount as a charge on their monthly bill.

9 **Q. Why should DEP wholesale power supply customers forgo paying a lower combined**  
10 **utility rate, even if only for a limited period of time?**

11 A. Put simply, *delayed* merger benefits are far superior to *no* merger benefits. DEP's existing  
12 wholesale power supply customers understand that without the Share the Benefits Plan,  
13 and their agreement to forgo paying the lower Carolinas 1U rate for a five-year transition  
14 period, it is highly unlikely that the Companies will obtain all of the required regulatory  
15 approvals to combine the Companies. Absent regulatory approval to effectuate the Internal  
16 Reorganization, DEP's existing wholesale power supply customers would continue to pay  
17 the higher DEP system rates and forego eventually receiving the equalization benefits, as  
18 well as the long-term savings and operational and planning efficiencies I described above.

19 **Q. What are the specific amounts of legacy system benefits that DEP's existing wholesale**  
20 **power supply customers are being asked to delay for the five-year transition period**  
21 **pursuant to the Share the Benefits Plan?**

22 A. Table 1 shows the amounts that each existing DEP wholesale power supply customer is  
23 being asked to delay during the five-year period:

1

Table 1

<b>Annual Existing DEP Wholesale Customer Contribution Amounts (\$ Thousands)<sup>6</sup></b>					
	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>	<b>Year 4</b>	<b>Year 5</b>
FBEMC	\$2,480	\$2,486	\$2,391	\$2,384	\$2,384
FPWC	\$8,619	\$8,640	\$8,310	\$8,286	\$8,286
HEMC	\$340	\$340	\$340	\$340	\$340
NCEMC	\$40,223	\$40,320	\$38,780	\$38,667	\$38,667
NCEMPA	\$38,304	\$38,396	\$36,929	\$36,822	\$36,822
<b>Total DEP Wholesale Contribution</b>	<b>\$89,967</b>	<b>\$90,182</b>	<b>\$86,750</b>	<b>\$86,500</b>	<b>\$86,500</b>

2

3 **Q. Are these amounts fixed for the five-year period?**

4 A. Yes. The amounts that will be added to DEP's existing wholesale power supply customers'  
5 bills over the five-year period are fixed and will be memorialized in an amendment to their  
6 respective wholesale power supply contracts. I will address the specifics of that process  
7 below, but the amounts will not change over the course of the five-year period.

8 **Q. Which customers will be allocated a portion of the amounts that are being collected  
9 annually from existing DEP wholesale power supply customers?**

10 A. The funds that are collected from DEP's existing wholesale power supply customers will  
11 be allocated to DEC's existing wholesale power supply customers and South Carolina retail  
12 customers.

13 **Q. Please explain how amounts collected from the Share the Benefits Plan will be  
14 allocated to DEC's existing wholesale power supply customers.**

15 A. Since DEC's existing wholesale power supply customers are expected to see increased  
16 rates as a result of the Internal Reorganization, the Share the Benefits Plan will allocate

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<sup>6</sup> A Contribution Amount is not listed for PEMC as PEMC intends to modify its DEP wholesale power supply contract to expire prior to January 1, 2027—Legal Day 1.

1 some of the retained savings from DEP's existing wholesale power supply customers to  
 2 DEC's existing wholesale power supply customers for the same five-year period. The  
 3 Companies calculated an annual amount for the five-year transition period that would  
 4 mitigate the rate impacts of the Internal Reorganization for each existing DEC wholesale  
 5 power supply customer and worked with each customer to derive a per-customer  
 6 Reorganization Amount in the form of an annual bill credit using their historical cost shift  
 7 impact as a basis.

8 **Q. Have the Companies calculated a per-customer amount that will be allocated to each**  
 9 **existing DEC wholesale power supply customer?**

10 A. Yes. Table 2 shows the amounts that will be credited to each existing DEC wholesale  
 11 power supply customer for the five-year transition period.

12 Table 2

<b>Annual Existing DEC Wholesale Customer Credit Amounts (\$ Thousands)</b>					
	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>	<b>Year 4</b>	<b>Year 5</b>
BREMC	\$2,760	\$2,760	\$2,760	\$2,760	\$2,760
Central	\$19,000	\$19,000	\$19,000	\$19,000	\$19,000
Dallas	\$235	\$297	\$0	\$0	\$0
Due West	\$47	\$54	\$0	\$0	\$0
Forest City	\$295	\$401	\$0	\$0	\$0
HEMC	\$320	\$320	\$320	\$320	\$320
Highlands	\$190	\$230	\$250	\$0	\$0
Lockhart	\$2,700	\$2,700	\$0	\$0	\$0
Orangeburg	\$2,500	\$2,500	\$2,500	\$2,500	\$2,500
Piedmont	\$1,700	\$1,700	\$1,700	\$1,700	\$1,700
NCEMC	\$1,500	\$1,500	\$1,500	\$1,500	\$1,500
REMC	\$3,720	\$3,720	\$3,720	\$3,720	\$3,720
<b>Total DEC Wholesale Credits</b>	<b>\$34,967</b>	<b>\$35,182</b>	<b>\$31,750</b>	<b>\$31,500</b>	<b>\$31,500</b>

1 **Q. Why does Table 2 show that some DEC wholesale power supply customers are**  
2 **receiving a credit under the Share the Benefits Plan for less than the full five-year**  
3 **transition period?**

4 A. Because some of DEC's wholesale power supply customers' contracts expire during the  
5 five-year period, these customers will not be allocated funds from the Share the Benefits  
6 Plan beyond their remaining contract terms. These customers will have the opportunity to  
7 either recontract with Carolinas 1U at the expiration of their respective contract, or shop  
8 for alternative supply.

9 **Q. Have the Companies discussed the Share the Benefits Plan with the legacy DEC**  
10 **wholesale power supply customers?**

11 A. Yes. The Companies have worked with their existing wholesale power supply customers  
12 to ensure that they understand the Equalization Effects associated with the Internal  
13 Reorganization and each DEC wholesale power supply customer is aware of the amounts  
14 that will be credited to their bill during the five-year transition period.

15 **Q. Why is it appropriate to limit the credit to DEC's existing wholesale power supply**  
16 **customers to a five-year period?**

17 A. The purpose of the Share the Benefits Plan is to address the short-term impacts of an  
18 internal corporate reorganization that is being undertaken to achieve long-term planning,  
19 execution and operational efficiencies and cost savings for the system, and to protect DEC's  
20 existing wholesale power supply customers from an immediate rate increase related to cost  
21 sharing of the DEP system. After Carolinas 1U has operated for five years, during which  
22 time DEC's existing wholesale power supply customers will have received a monthly

1 credit, it will be appropriate for DEC's existing wholesale power supply customers to pay  
2 a merged rate structure.

3 **Q. In addition to DEC's existing wholesale power supply customers, you previously**  
4 **noted that the Companies' existing South Carolina retail customers will receive funds**  
5 **from the Share the Benefits Plan. What amount will be credited to the Companies'**  
6 **South Carolina retail customers?**

7 A. In her testimony filed in support of the Companies' applications filed with the North  
8 Carolina Utilities Commission and the Public Service Commission of South Carolina,  
9 Company witness Rachel Elliott explains how amounts collected from current DEP  
10 wholesale power supply customers that are not dedicated to funding the offsetting credits  
11 to existing DEC wholesale power supply customers will be used to mitigate the impact of  
12 the cost reallocation to the Companies' customers in the South Carolina retail jurisdiction.  
13 That amount is \$55 million per year for the same five-year transition period, which is the  
14 net of the Contribution and Credit Amounts reflected in Tables 1 and 2 above.

15 **Q. Will there be any sort of true-up under the Share the Benefits Plan?**

16 A. No. Because we are fixing the amounts collected from DEP's existing wholesale power  
17 supply customers for the five-year term, and similarly fixing the amounts credited to DEC's  
18 existing wholesale power supply customers and the Companies' South Carolina retail  
19 customers for the five-year term, there will be no need for a true-up. Moreover, this fixed  
20 amount approach represents a reasonable compensatory proxy value that mitigates the  
21 amount of the immediate rate impact these customers should expect based on legacy system  
22 costs.

1           The Companies opted not to attempt to make this value formulaic or otherwise float  
2 over the five-year term for several reasons. First, with each year that passes under a merged  
3 utility it becomes virtually impossible to replicate what rates *would have been* had a  
4 corporate consolidation not taken place. Second, these amounts are intended to mimic the  
5 impacts of the Equalization Effect on the legacy system costs that exist at the time of the  
6 Internal Reorganization, so calculating a fixed amount based on historical system costs is  
7 reasonable. Third, the respective customers of both DEC and DEP generally prefer rate  
8 certainty, and the fixed value approach in the Share the Benefits Plan accomplishes this  
9 objective.

10           **V. IMPLEMENTATION OF THE SHARE THE BENEFITS PLAN**

11 **Q. Focusing on the Companies' wholesale power supply business, please explain how the**  
12 **Share the Benefits Plan will be implemented.**

13 A. Each of the amounts noted in Tables 1 and 2 above will be reflected in amendments to each  
14 customer's respective wholesale power supply agreement. For DEP's existing wholesale  
15 power supply customers, the Reorganization Amount will be collected through a charge  
16 added to each customer's respective wholesale power supply contract. As explained above,  
17 the amount of each customer's Reorganization Amount will be fixed for the five-year  
18 period and will not be subject to fluctuations in Carolinas 1U's cost of service during this  
19 time period. Similarly, for DEC's existing wholesale power supply customers, the  
20 Reorganization Amount will be given as a credit that will be added to each customer's

1           respective wholesale power supply contract. These amounts will also be fixed for the five-  
2           year period and will not be subject to fluctuations in Carolinas 1U's cost of service.<sup>7</sup>

3           I want to emphasize that the Reorganization Amounts will be made as *billing*  
4           adjustments, and thus, they will not impact the formulaic calculation of rates under  
5           individual wholesale power supply contracts and will not depend on the customer's actual  
6           usage or demand during a particular month or year. Instead, the formula rates under all  
7           wholesale power supply contracts will continue to produce charges on a Carolinas 1U basis,  
8           and each customer's monthly invoice will include either an administratively added  
9           Reorganization Amount as a charge or credit as reflected in the above tables.

10 **Q.   Please explain how the Companies intend to amend their existing wholesale power**  
11 **supply contracts.**

12 A.   The Companies plan to amend their existing wholesale power supply agreements to add  
13       the Reorganization Amounts to the legacy DEP and legacy DEC wholesale power supply  
14       contracts. As stated above, the applicable Reorganization Amount will be applied as a  
15       separately stated charge or credit to each existing wholesale power supply contract.

16 **Q.   When do the Companies expect to amend each of DEC and DEP's existing wholesale**  
17 **power supply agreements?**

18 A.   Amending these existing long-term power supply agreements is a complicated and time-  
19       intensive process. The Companies are working with their existing wholesale power supply  
20       customers and intend to make the necessary amendments in the coming months. Each

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<sup>7</sup> The Reorganization Amounts will be applicable for a five-year period, except for (i) DEC's wholesale power supply contracts with Dallas, Due West, Forest City, and Lockhart which will last until those contracts expire in 2028, and (ii) DEC's wholesale power supply contract with Highlands, which will last until that contract expires in 2029.

1 amended contract will be filed with the Commission once the Internal Reorganization is  
2 approved. For purposes of the instant filing, however, the Share the Benefits Plan is central  
3 to this application's demonstration that the short-term impacts of the Internal  
4 Reorganization have been adequately mitigated.

## 5 VI. CONCLUSION

6 **Q. Please summarize your testimony.**

7 A. As with all corporate reorganizations, there will be impacts that affect each jurisdiction  
8 differently. However, with the Share the Benefits Plan, the Companies have crafted a  
9 mitigation plan that appropriately delays the benefits of the Internal Reorganization for one  
10 customer class (DEP's existing wholesale power supply customers) and mitigates cost  
11 reallocation impacts to other customer classes (DEC's existing wholesale power supply  
12 customers and the Companies' South Carolina retail customers). My testimony, which is  
13 focused on the Companies' wholesale power supply business, demonstrates that *delayed*  
14 merger benefits are far superior to *no* merger benefits at all. Absent regulatory approval to  
15 effectuate the Internal Reorganization, DEP's existing wholesale power supply customers  
16 will continue to pay the higher DEP system rates, and all customers would forgo benefiting  
17 from the planning and operational efficiencies resulting from a combined utility, along with  
18 the long-term system savings I mentioned above.

19 **Q. Does this conclude your testimony?**

20 A. Yes.

UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION


Duke Energy Corporation )  
Duke Energy Carolinas, LLC ) Docket No. EC25-\_\_\_-000  
Duke Energy Progress, LLC )

PREPARED DIRECT TESTIMONY OF JENNIFER S. ELLIS

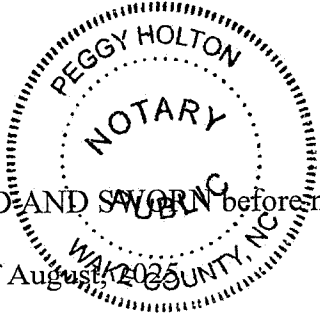
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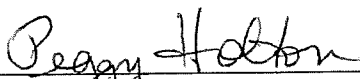
State of North Carolina )  
)

I, Jennifer S. Ellis, being first duly sworn, state that I am the witness identified in the foregoing prepared testimony, and that the statements of fact in the testimony are true and correct to the best of my knowledge, information, and belief.

  
\_\_\_\_\_  
Jennifer S. Ellis

SUBSCRIBED AND SWORN before me  
the 14 day of August, 2025  
WAKE COUNTY, NC



  
\_\_\_\_\_  
Notary Public

My commission expires on: 12/22/2026

**Attachment 3**  
**Prepared Direct Testimony of Blain Atkins**

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

**Duke Energy Corporation** )  
**Duke Energy Carolinas, LLC** ) **Docket No. EC25-\_\_\_\_-000**  
**Duke Energy Progress, LLC** )

**PREPARED DIRECT TESTIMONY OF  
BLAIN ATKINS  
ON BEHALF OF  
DUKE ENERGY CORPORATION,  
DUKE ENERGY CAROLINAS, LLC AND  
DUKE ENERGY PROGRESS, LLC**

**August 14, 2025**

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

**Duke Energy Corporation** )  
**Duke Energy Carolinas, LLC** ) **Docket No. EC25-\_\_\_\_-000**  
**Duke Energy Progress, LLC** )

**PREPARED DIRECT TESTIMONY OF  
BLAIN ATKINS  
ON BEHALF OF  
DUKE ENERGY CORPORATION,  
DUKE ENERGY CAROLINAS, LLC AND  
DUKE ENERGY PROGRESS, LLC**

**I. INTRODUCTION**

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**Q. Please state your name and business address.**

A. I am Blain Atkins. My business address is 525 South Tryon Street, Charlotte, North Carolina, 28202.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Duke Energy Carolinas, LLC (“DEC”) as Director – Carolinas Wholesale Rates and Regulatory.

**Q. Please briefly describe your educational background and employment history.**

A. In 2007, I received a Bachelor of Science degree in Industrial Engineering from North Carolina State University. Upon graduation, I joined DEC as a Load Forecaster. Over the years, I have held various positions within the Fuels and System Optimization department in the areas of load forecasting and power marketing before joining the Wholesale Power Sales group in 2017. I assumed my current position as Director – Carolinas Wholesale Rates and Regulatory in July 2024.

1 **Q. Please describe your duties and responsibilities as Director of Carolinas Wholesale**  
2 **Rates and Regulatory.**

3 A. In this role, I lead the group responsible for the rate design and strategy for the wholesale  
4 power supply and Joint Open Access Transmission Tariff (“Joint OATT”) of DEC and  
5 Duke Energy Progress, LLC (“DEP,” together, with DEC, the “Companies”). These  
6 responsibilities include developing and implementing wholesale rate structures and  
7 ensuring that wholesale rate designs align with cost of service principles, regulatory  
8 policies, and corporate financial goals.

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

10 A. The purpose of my testimony is to discuss the benefits and impacts of the proposed  
11 internal corporate reorganization (the “Internal Reorganization”) in which DEP will merge  
12 with, and into DEC, with DEC being the surviving entity, on the Companies’ Joint OATT  
13 customers. The Companies are requesting approval for the Internal Reorganization from  
14 the Federal Energy Regulatory Commission (“FERC” or the “Commission”) in order to  
15 consummate the Internal Reorganization on January 1, 2027 (“Legal Day 1”). As a result  
16 of the Internal Reorganization, a single electric utility (“Carolinas 1U”) will serve all  
17 existing wholesale and retail customers in the legacy DEC and legacy DEP service  
18 territories.

19 My testimony provides an overview of the impacts of the Internal Reorganization  
20 on the Companies’ Joint OATT customers and addresses the Companies’ proposed three-  
21 part “OATT Mitigation Plan,” a component of the Companies’ rate mitigation plan (“1U  
22 Rate Mitigation Plan”) that addresses the short-term cost reallocations resulting from the  
23 Internal Reorganization on transmission rates under the Companies’ Joint OATT.

1 **Q. Are you sponsoring any exhibits in connection with your testimony?**

2 A. Yes. I am sponsoring the following exhibits, which are attached to and made a part of my  
3 testimony:

4 Exhibit 1: Calculation of Equalization Effect

5 **Q. To the extent that any of your exhibits involve mathematical calculations or**  
6 **interpretations of data, were all such calculations and interpretations performed by**  
7 **you or under your supervision?**

8 A. Yes. Members of my team assisted with many of these calculations, but I can attest to their  
9 accuracy.

10 **Q. How would you summarize the impact of the Internal Reorganization on the**  
11 **Companies' Joint OATT customers?**

12 A. The Internal Reorganization is being pursued for the various long-term benefits it will  
13 provide to all DEC and DEP customers. Witness Nelson Peeler discusses how the  
14 Companies have identified quantitative and qualitative long-term benefits for customers,  
15 including operational efficiencies and the ability to make more efficient generating  
16 capacity investment decisions, resulting in sizeable system-level savings. My testimony is  
17 focused on how the Internal Reorganization will impact the Companies' Joint OATT  
18 customers and how the OATT Mitigation Plan will provide rate mitigation measures to  
19 these customers.

20 **II. OVERVIEW OF THE COMPANIES' JOINT OATT AND JOINT OATT**  
21 **CUSTOMERS**

22 **Q. What is an OATT?**

23 A. An OATT is a regulatory document that outlines the terms and conditions under which a  
24 utility's transmission and distribution facilities are made available to other parties for the

1 transmission of electricity. Its primary purpose is to ensure non-discriminatory access to  
2 transmission infrastructure for wholesale electricity transactions.

3 **Q. Please explain the origin of the Companies' Joint OATT.**

4 A. As part of the 2012 merger between Duke Energy Corporation (“Duke Energy”) and  
5 Progress Energy, Inc. (“Progress Energy”),<sup>1</sup> Duke Energy on its own behalf and on behalf  
6 of its public utility subsidiary, DEC, and Progress Energy, on its own behalf and on behalf  
7 of its public utility subsidiaries Carolina Power & Light Company d/b/a Progress Energy  
8 Carolinas, Inc. (“PEC”)<sup>2</sup> and Florida Power Corporation d/b/a Progress Energy Florida,  
9 Inc. (“PEF”),<sup>3</sup> filed the Joint OATT with the Commission. The Joint OATT combined the  
10 then-existing DEC OATT, PEC OATT, and PEF OATT into a single document to govern  
11 the transmission services offered by the surviving entities following the Duke/Progress  
12 Merger: DEC, DEP, and DEF (collectively, the “Duke Utility Subsidiaries”). The Joint  
13 OATT allowed each of the Duke Utility Subsidiaries to keep their current jurisdictional  
14 rates. Since 2012, the Joint OATT has served as the governing document for the Duke  
15 Utility Subsidiaries.

16 **Q. Please explain the structure of the Joint OATT today.**

17 A. Today, Duke Energy maintains two separate pricing zones in the Carolinas—one for DEC  
18 and another for DEP. As mentioned above, Duke Energy maintains a single OATT—the  
19 Joint OATT—that applies to the Duke Utility Subsidiaries. While the common service  
20 provisions of the Joint OATT apply to all of the Duke Utility Subsidiaries, each of the Duke

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1 On July 2, 2012, Duke Energy and Progress Energy, then the parent companies of, respectively, DEC and DEP, closed their merger transaction pursuant to which Progress Energy became a wholly-owned subsidiary of Duke Energy (the “Duke/Progress Merger”).

2 PEC is now DEP.

3 PEF is now DEF.

1 Utility Subsidiaries maintains its own formula rate template and protocols within the Joint  
2 OATT.

3 **Q. What is a Balancing Authority (“BA”) and how many BAs does Duke Energy have in**  
4 **the Carolinas?**

5 A. A BA manages the operation of the electric system within a specific geographic area. There  
6 are more than 60 BAs in the United States, and they are typically either utilities, power  
7 marketing administrations, or a group of utilities that have formed regional entities called  
8 regional transmission organizations and independent system operators. There are two  
9 Duke BAs in the Carolinas: DEP and DEC, with each serving as the BA for their respective  
10 system.

11 **Q. What is a Balancing Authority Area (“BAA”) and how many are there on the Duke**  
12 **Energy system in the Carolinas today?**

13 A. A BAA is a geographically defined region where a BA is responsible for maintaining the  
14 balance between electricity supply and demand within that area. This involves managing  
15 generation, transmission, and load within the BAA’s metered boundaries, ensuring the  
16 grid’s stability and reliable operation. There are currently three BAAs on the Duke Energy  
17 system in the Carolinas: DUK, CPLE, and CPLW. DEC operates the DUK BAA (DEC  
18 BA), and DEP operates the CPLE and CPLW BAAs (DEP BA).

19 **Q. Do OATT customers for DEC and DEP pay the same OATT rates?**

20 A. No. The DEC BA and DEP BA each have their own rates. DEC has its own formula rate  
21 template that applies to the DEC BA, and DEP similarly has its own formula rate template  
22 that applies to the DEP BA.

23 **Q. Who are the Companies’ current Joint OATT customers?**

1 A. Currently, DEC has 29 Joint OATT customers, and DEP has 15 Joint OATT customers.<sup>4</sup>

2 **Q. Historically and currently, how do these separate transmission rates compare**  
 3 **between the DEC and DEP BAs?**

4 A. Transmission rates tend to be lower in the DEC BA than in the DEP BA, but not  
 5 substantially. This differential is largely due to DEC having a larger customer base and  
 6 there being more capital investment in the DEP BA.<sup>5</sup> Table 1 below illustrates the  
 7 differences between the transmission rates as between the DEP and DEC BAs. As shown  
 8 in Table 1, DEP transmission rates tend to be a bit higher.

9 Table 1

<b>5 Year Summary of DEC &amp; DEP Transmission Rates \$/MW-Month</b>		
<b>\$/MW-Month:</b>	<b>DEC</b>	<b>DEP</b>
2024 Annual Update (2023 FF1)	1,804	2,237
2023 Annual Update (2022 FF1)	1,887	2,016
2022 Annual Update (2021 FF1)	1,311	1,935
2021 Annual Update (2020 FF1)	1,738	1,859
2020 Annual Update (2019 FF1)	1,270	1,479

10 **Q. What are ancillary services and do the Companies also maintain separate ancillary**  
 11 **services rates?**

12 A. Ancillary services maintain grid reliability and support the transmission of electricity. DEC  
 13 and DEP each provide ancillary services under four rate schedules, as specified in Table 2  
 14 below, but each company maintains its own ancillary services rates. For instance, service  
 15 under Schedule 1 is required to schedule the movement of power through, out of, within,

<sup>4</sup> See Exhibit F to the Section 203 application.

<sup>5</sup> Witness Peeler's testimony discusses how geographic differences between the service territories of legacy DEC and legacy DEP make each legacy service territory more optimal for siting and building certain types of generation resources than the other.

1 or into a Control Area, and service under Schedule 5 allows for serving load immediately  
 2 in the event of a system contingency. Although customers must take service under  
 3 Schedule 1, they can choose to take the other ancillary services from the Companies, or  
 4 they can elect to self-serve.

5 **Q. Are DEC's ancillary service rates also generally lower than DEP's ancillary services**  
 6 **rates?**

7 A. No. While the ancillary services rates differ between the Companies' jurisdictions, some  
 8 ancillary services rates are higher for legacy DEC customers and others are higher for  
 9 legacy DEP customers. Table 2 highlights these differences.

10 Table 2

<b>Current DEC &amp; DEP Ancillary Services Rates</b>		
	<b>DEC Rate</b>	<b>DEP Rate</b>
Schedule 1 - Scheduling, System Control & Dispatch Service	\$ 55.00	\$36.50
Schedule 3 - Regulation & Frequency Response Service	\$ 38.00	\$47.52
Schedule 5 - Spinning Reserve Service	\$ 81.50	\$70.09
Schedule 6 - Supplemental Reserve Service	\$ 81.50	\$50.09

11 **III. IMPACT OF INTERNAL REORGANIZATION ON JOINT OATT RATES**

12 **Q. Did the Companies undertake any analysis to understand the impact of the Internal**  
 13 **Reorganization on the Companies' Joint OATT rates?**

14 A. Yes. The Companies calculated pro forma versions of what a single utility's OATT rate  
 15 would produce by merging DEC and DEP's revenue requirements and their respective  
 16 loads. Then, because the Internal Reorganization is not expected to occur until January 1,  
 17 2027—Legal Day 1—we considered our forecasted revenue requirements for each of the  
 18 Companies to better understand the impact of the Internal Reorganization on rates beyond  
 19 2027.

1 **Q. Did the rate forecasts help the Companies understand and assess the impact of the**  
2 **Internal Reorganization on the Companies' Joint OATT rates?**

3 A. Somewhat. By that, I mean that both DEC and DEP are currently projecting significant  
4 investment in their respective transmission systems over the next several years. As a result,  
5 it is highly likely that both Companies' will see increases in the Joint OATT rates as a result  
6 of capital investments, regardless of whether the Companies consolidate. Therefore, the  
7 Companies took a closer look to identify the factors leading to an impact on the Joint OATT  
8 rates that would result from a corporate consolidation.

9 **Q. What did that analysis reveal?**

10 A. As is common with any combination of two revenue requirements, the resulting merged  
11 Joint OATT rates will reflect some degree of equalization such that the merged rates will  
12 be lower for some customers and higher for other customers in the short run. In this case,  
13 DEC's transmission rates are projected to increase in the short run following the Internal  
14 Reorganization (because it is the lower-cost system), and DEP's transmission rates are  
15 projected to decrease in the short run (because it is the higher-cost system). I refer to this  
16 outcome as the "Equalization Effect." My testimony addresses the Equalization Effect as  
17 it applies to the Companies' Joint OATT rates, and witness Jennifer Ellis addresses the  
18 Equalization Effect as it applies to the Companies' wholesale power supply rates.

19 **Q. Were the Companies able to quantify the Equalization Effect?**

20 A. Yes. To estimate the impact of the Equalization Effect, the Companies analyzed FERC  
21 Form 1 data from the 2024 true-up (i.e., for the 2023 rate year). Using this data, we first  
22 merged the revenue requirements and the load divisors of the Companies and compared  
23 the merged revenue requirement to existing rates for 2023. This exercise enabled the

1 Companies to determine that approximately \$37 million, or approximately 8%, of the  
2 revenue requirement “shifted” from DEP to DEC transmission customers under a  
3 consolidated utility structure. It is important to note that the \$37 million estimate is a  
4 *system-wide* number, meaning that third-party Joint OATT customers only bear a portion  
5 of this amount. This calculation is shown in Exhibit 1 to my testimony.

6 **Q. What percentage of the \$37 million would be borne by third-party Joint OATT**  
7 **customers on the DEC system?**

8 A. As shown in Exhibit 1, legacy DEC third-party Joint OATT customers’ share of the \$37  
9 million is approximately 23% (or \$8.5 million) based on the DEC Joint OATT customers’  
10 share of transmission system load.

11 **Q. In addition to the Equalization Effect, is there another reason why the Internal**  
12 **Reorganization will impact the Companies’ Joint OATT rates?**

13 A. Yes. The second impact our analysis revealed was less intuitive and arises out of the unique  
14 nature of Duke Energy’s system today. When we modeled Carolinas 1U, we noticed a drop  
15 in the load divisor as compared to merely adding today’s load divisors of DEP and DEC  
16 together, as we did for the Companies’ respective revenue requirements. The drop in the  
17 load divisor is a result of eliminating various point-to-point (“PTP”) reservations between  
18 the legacy DUK, CPLE, and CPLW BAAs. I refer to this result as the “Divisor Effect”  
19 which I explain in more depth below.

20 **Q. Please explain why eliminating PTP reservations between the Carolinas’ three**  
21 **existing BAAs results in the Divisor Effect.**

22 A. Following the Duke/Progress Merger, Duke Energy and Progress Energy planned to  
23 maintain three separate legacy BAAs—the DUK, CPLE, and CPLW BAAs. Today, as a

1 result of maintaining three separate BAAs, the Companies' transmission customers need  
2 PTP transmission service to wheel power from one Duke Energy BAA to load in another  
3 Duke Energy BAA. These Duke Energy PTP reservations are *in addition* to the network  
4 service reserved for DEC and DEP native load. In setting transmission rates today, these  
5 PTP reservations are included in the divisor with all other loads, and their presence  
6 *increases* the denominator, which in turn *lowers* the resulting Joint OATT rate for all Joint  
7 OATT customers.

8 However, after the consolidation of BAAs that will happen commensurate with the  
9 Internal Reorganization, neither Carolinas 1U nor any other transmission customer will  
10 need to reserve PTP service to move power across the legacy DEC and DEP systems. As  
11 such, these PTP reservations will no longer appear in the rate calculation and, all else being  
12 equal, this single change will result in the Divisor Effect—namely, a decrease in the  
13 Carolinas 1U rate denominator, which results in an increase on the Carolinas 1U OATT  
14 rates due to the fewer megawatts (“MW”) of demand in the denominator over which to  
15 spread the revenue requirement.

16 **Q. Were you able to quantify these PTP reservations across the three Duke Energy**  
17 **BAAs?**

18 A. Yes. The DEC and DEP PTP reservations total approximately 34,000 MW months  
19 annually, which is roughly 10% of the combined total historical annual loads under the  
20 DEC and DEP Joint OATT rates. As explained above, however, because PTP reservations  
21 between the legacy DEC and DEP systems will be eliminated after the Internal  
22 Reorganization, they will no longer appear in the rate calculation and, all else being equal,  
23 this one change will result in an approximately 10% decrease in the Carolinas 1U OATT

1 rate denominator, creating *upward* pressure on the Carolinas 1U OATT rates as there will  
2 be fewer MW of demand in the denominator over which to spread the revenue requirement.

3 **Q. Is this change in denominator treatment appropriately considered a rate increase?**

4 A. In viewing this change, I think it is crucial to consider that for over a decade, third-party  
5 transmission customers have received a subsidy from the double-counting of some amount  
6 of DEC or DEP load in the divisor since it showed up in both PTP and network service.  
7 Eliminating PTP service reflects a more accurate picture of the total actual load in what  
8 will be a single Duke Energy BAA, and Carolinas 1U will still pay its fair share of the costs  
9 of the system.

10 **Q. In addition to the Equalization Effect and Divisor Effect, did the Companies consider**  
11 **the impact of the Internal Reorganization on ancillary services rates, and whether it**  
12 **would be appropriate to update ancillary services rates ahead of the Internal**  
13 **Reorganization?**

14 A. We did. We began a process of calculating what ancillary services rates might look like  
15 under a merged company model and began socializing those issues with customers. In the  
16 end, asking the customers to engage in what is essentially a full ancillary services rate case  
17 seemed too much to ask of them. Another consideration is that with the exception of  
18 Schedule 1 for DEC,<sup>6</sup> the Companies have not updated these rates for some time, and as a  
19 result, any change would likely be drastic simply because of the time that has lapsed since  
20 the last rate change.

21 **Q. Do the Companies have a plan for addressing the rate impacts on the Joint OATT and**  
22 **ancillary services associated with the Internal Reorganization?**

---

<sup>6</sup> DEC Schedule 1 is a formula rate that is updated on an annual basis.

1 A. Yes. The Companies are offering a three-part OATT Mitigation Plan to address the  
2 Equalization Effect and the Divisor Effect for legacy DEC customers, and the rates for  
3 ancillary services for all Joint OATT customers following the Internal Reorganization.

#### 4 **IV. OATT RATE MITIGATION PLAN**

5 **Q. The Section 203 application and other supporting testimony reference a “Share the**  
6 **Benefits Plan.” Is the three-part OATT Mitigation Plan part of the Share the Benefits**  
7 **Plan?**

8 A. No. As explained by witness Ellis, the Share the Benefits Plan addresses cost reallocations  
9 between the legacy DEC and legacy DEP wholesale power supply customers, as well as  
10 between the wholesale and retail jurisdictions. The OATT Mitigation Plan consists of the  
11 “Equalization Adjustment,” “Divisor Adjustment,” and “Ancillary Services Adjustment.”  
12 Each of these three components are self-contained within the OATT Rate Mitigation Plan.  
13 I define and describe each of these components below.

#### 14 **A. EQUALIZATION ADJUSTMENT**

15 **Q. Please explain the Companies’ proposal to mitigate the Equalization Effect.**

16 A. As I previously mentioned, the Companies estimate the impact of the Equalization Effect  
17 to be approximately \$37 million per year on a system-wide basis. To address the  
18 Equalization Effect, the Companies propose to lower the revenue requirement for purposes  
19 of calculating rates for legacy DEC customers for a five-year transitional period. The  
20 Companies will phase out this revenue requirement reduction proportionally over the five-  
21 year period as shown in Table 3.

Table 3

	Year 1 <sup>7</sup>	Year 2	Year 3	Year 4	Year 5
DEC Cost Shift Revenue Requirement Adj (\$000s)	(37,139)	(29,711)	(22,283)	(14,856)	(7,428)

**Q. You previously noted that legacy DEC Joint OATT customers would be impacted by the Equalization Effect if no adjustments are made. How does the Equalization Adjustment mitigate this effect?**

**A.** *For illustration purposes only*, Table 4 contains forecasted estimates of the rate effects of the Equalization Adjustment on legacy DEC Joint OATT customers. The Companies' proposal does not rely on the accuracy of these forecasts; rather, as a manual decrease to the numerator, the Equalization Adjustment will only serve to lower rates.

Table 4

<b>\$/MW-Month Cost Shift Adjustment Impact to DEC Legacy Customers</b>					
<b>Forecasted 1U \$/MW-Month Rate</b>	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>	<b>Year 4</b>	<b>Year 5</b>
1U \$/MW-Month Rate Unadjusted	2,885	3,205	3,574	3,988	4,371
1U \$/MW-Month Rate with Rev. Req. Adj.	2,796	3,134	3,520	3,952	4,353
<b>\$/MW-Month Difference</b>	<b>(89)</b>	<b>(71)</b>	<b>(54)</b>	<b>(36)</b>	<b>(18)</b>

**Q. Why are the Companies proposing to phase out the Equalization Adjustment proportionally over a five-year period?**

**A.** Effective Legal Day 1, all Carolinas 1U OATT customers will start to see the benefit of coordinated operations and planning. It is equitable to phase out the Equalization Adjustment as the benefits of the Internal Reorganization are phasing in.

<sup>7</sup> Year 1 in Tables 3 through 6 and Table 8 represents the 2028 OATT Annual Update.

1 **Q. Did the Companies consider calculating the Equalization Effect each year, starting**  
2 **with Legal Day 1, and then fashioning a mitigation plan based on that?**

3 A. Yes. We analyzed such a concept but it quickly became clear that it was unworkable. Once  
4 the Companies combine—and planning and operational decisions and capital investments  
5 begin being made on a single-company basis—it will be impossible to recreate a scenario  
6 under which the Companies do not combine for a five-year period. There will be no  
7 separate FERC Form 1s and no realistic estimate of what legacy DEC and DEP each *would*  
8 *have* spent to operate separate transmission systems over the five-year period. Moreover,  
9 the fact that both DEC and DEP are projecting to make considerable capital investment in  
10 their transmission systems over this five-year study period exacerbates the challenges of  
11 creating hypothetical separate revenue requirements over the course of this transition  
12 period.

13 **Q. Did the Companies consider using a percentage instead of a fixed amount for the**  
14 **Equalization Effect?**

15 A. Yes. As I explained above, the revenue requirement shift associated with the Equalization  
16 Effect is approximately eight percent (8%). The Companies considered, but ultimately  
17 rejected, a percentage basis revenue requirement reduction because a percentage basis  
18 reduction creates rate uncertainty for both the Companies and customers and creates undue  
19 risk for the Companies as the revenue requirement grows in response to capital investments  
20 in transmission.

21 **Q. Do you have any other comments on the proposal to mitigate the Equalization Effect?**

22 A. Yes, because the Companies' Joint OATT rates for the Companies are not that far apart  
23 today, the fact that these rates will combine after the Internal Reorganization does not

1 necessarily warrant a mitigation plan. As such, I believe that the Equalization Adjustment  
2 is more than sufficient to mitigate any cost reallocations resulting from the Internal  
3 Reorganization.

4 **Q. Will the Equalization Adjustment apply to Network Integration Transmission Service**  
5 **(“NITS”) and PTP rates?**

6 A. Yes.

7 **Q. How will Carolinas 1U identify the legacy DEC Joint OATT customers to whom the**  
8 **Equalization Adjustment will apply?**

9 A. All of the legacy DEC NITS customers as of the date of this filing will benefit from the  
10 Equalization Adjustment. For legacy DEC PTP customers, the company will apply the  
11 Equalization Adjustment for those customers with existing (as of the date of this filing)  
12 long-term PTP reservations for which the term or roll-over right extends past the planned  
13 January 1, 2027, effective date of the Internal Reorganization.

#### 14 **B. THE DIVISOR ADJUSTMENT**

15 **Q. Please explain the Companies’ proposal to mitigate the Divisor Effect.**

16 A. Since neither the Companies nor other Joint OATT customers will need to reserve PTP  
17 service between the legacy Duke Energy BAAs after the Internal Reorganization, Carolinas  
18 1U will have a smaller rate divisor for the same amount of load which, if unmitigated,  
19 would create upward pressure on rates. To address the Divisor Effect, the Companies are  
20 proposing a ratemaking adjustment for legacy DEC Joint OATT customers in which the  
21 Companies reinstate a fixed amount of MW into the Joint OATT divisor. I refer to this  
22 ratemaking adjustment as the “Divisor Adjustment.” The Divisor Adjustment will be in

1 effect for five years and will be reduced each year across the five-year period, as shown in  
2 Table 5.

3 Table 5

	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>	<b>Year 4</b>	<b>Year 5</b>
MW Divisor Adjustment	36,120	28,896	21,672	14,448	7,224

4  
5 **Q. How did the Companies calculate the Divisor Adjustment?**

6 A. Actual 2024 long-term firm (“LTF”) PTP reservations between DEC and DEP (36,120  
7 MW) were utilized to derive the Divisor Adjustment for Year 1 (calendar year 2027).

8 **Q. Like the Equalization Adjustment, did the Companies consider updating these values  
9 over time?**

10 A. We considered it but quickly realized it would be inappropriate. The most important thing  
11 we can do for our customers is to provide rate certainty. We did not want to ask customers  
12 to accept a moving target as a mitigation measure. Had we asked customers to agree to,  
13 for example, the MW representing the Companies’ point-to-point reservations in calendar  
14 year 2026, they would have had understandable consternation about how that value might  
15 diminish as the Companies approach the Internal Reorganization. Therefore, rather than  
16 asking legacy DEC Joint OATT customers to agree to an uncertain adjustment, the  
17 Companies opted to develop a mitigation proposal that would provide rate certainty to the  
18 Companies and customers alike. Therefore, the Divisor Adjustment amounts are fixed and  
19 will not change over the five-year period based on other cost of service inputs.

20 **Q. You noted above that without the Divisor Adjustment, legacy DEC Joint OATT  
21 customers would be paying higher Joint OATT rates under Carolinas 1U. How does  
22 the Divisor Adjustment mitigate this impact?**

1 A. *For illustration purposes only*, Table 6 contains forecasted estimates of the rate effects to  
 2 legacy DEC Joint OATT customers resulting from the Divisor Adjustment. Importantly,  
 3 the Divisor Adjustment (like the Equalization Adjustment) does not rely on the accuracy  
 4 of forecasts; rather, as a manual increase to the load divisor, this rate adjustment will only  
 5 result in lower Joint OATT rates for legacy DEC Joint OATT customers.

6 Table 6

<b>\$/MW-Month MW Divisor Adjustment Impact to DEC Legacy Customers</b>					
<b>Forecasted 1U \$/MW-Month Rate</b>	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>	<b>Year 4</b>	<b>Year 5</b>
1U \$/MW-Month Rate Unadjusted	2,885	3,205	3,574	3,988	4,371
1U \$/MW-Month Rate with MW Adj.	2,635	2,983	3,387	3,849	4,295
<b>\$/MW-Month Difference</b>	<b>(250)</b>	<b>(222)</b>	<b>(186)</b>	<b>(139)</b>	<b>(76)</b>

7

8 **Q. Will legacy DEP Joint OATT customers see lower Joint OATT rates even with the**  
 9 **Divisor Adjustment?**

10 A. Yes. As shown in Table 8 below, the current DEP OATT rate is higher than the unadjusted  
 11 1U rate – meaning that DEP Joint OATT customers will see lower Joint OATT rates without  
 12 ever needing a Divisor Adjustment. This is why it is appropriate to only apply the Divisor  
 13 Adjustment to legacy DEC Joint OATT customers.

14 **Q. Why is it appropriate to phase out the Divisor Adjustment?**

15 A. There are a number of reasons. While it is entirely appropriate to mitigate the Divisor  
 16 Effect, we do not think that the Companies' Joint OATT customers should have an  
 17 indefinite subsidy resulting from the use of PTP service between the legacy Duke Energy  
 18 BAAs. Similar to the phase-out of the Equalization Adjustment over a five-year period, it  
 19 is appropriate to phase out the Divisor Adjustment over that same period because the OATT  
 20 rates for Carolinas 1U will reflect the actual costs of the merged company, and the  
 21 efficiencies gained from the Internal Reorganization will be increasingly reflected in rates.

1 Moreover, even without the Divisor Adjustment, the Companies' third-party Joint OATT  
2 customers will only be asked to pay Carolinas 1U's cost of service spread over all of the  
3 demand in the combined BA. With these considerations in mind, phasing out the Divisor  
4 Adjustment over five years is entirely equitable.

5 **Q. Are the Companies' proposals to mitigate the Equalization Effect and Divisor Effect**  
6 **additive?**

7 A. Yes. The Equalization Adjustment and the Divisor Adjustment are additive. That is, each  
8 calculation will happen separately, and independent of the other, and will result in a stand-  
9 alone deduction for legacy DEC Joint OATT customers.

10 **Q. You mentioned that the Equalization Adjustment and the Divisor Adjustment are**  
11 **limited to legacy DEC Joint OATT customers. Why aren't the Companies proposing**  
12 **rate mitigation proposals for legacy DEP Joint OATT customers?**

13 A. Because legacy DEP Joint OATT customers will see immediate rate reductions resulting  
14 from the Internal Reorganization, the Equalization Adjustment and the Divisor Adjustment  
15 are limited to legacy DEC Joint OATT customers.

16 **Q. Will the Divisor Adjustment apply to NITS and PTP rates?**

17 A. Yes.

18 **Q. How will Carolinas 1U identify the legacy DEC Joint OATT customers to whom the**  
19 **Divisor Adjustment will apply?**

20 A. We will identify the universe of customers to receive the Divisor Adjustment in the same  
21 way we will for the Equalization Adjustment, as I described above.

**C. ANCILLARY SERVICES ADJUSTMENT**

**Q. Please explain the Companies' proposal to address ancillary services rates.**

A. Rates for ancillary services present a different challenge than transmission rates. Between DEC and DEP, the rates for ancillary services are not uniformly higher or lower. As a result, the Companies decided to develop a mitigation proposal based on the "lower of" approach. Specifically, for a two-year period (calendar years 2027 and 2028), Carolinas 1U will adopt the ancillary services rate that is the lower of the existing rates of legacy DEC or DEP. I refer to this mitigation measure as the "Ancillary Services Adjustment." Carolinas 1U would reserve its right to file for updated ancillary services rates, effective no earlier than two years after Legal Day 1 (i.e., January 1, 2029).

**Q. What rates will be charged for ancillary services during the two-year moratorium period?**

A. Table 7 sets forth the Ancillary Services Adjustment which adopts the "lower of" rate for each of the ancillary services.

Table 7

<b>Lower of DEC-DEP Ancillary Services for Calendar Years 2027 and 2028</b>			
	<b>Current DEC Rate</b>	<b>Current DEP Rate</b>	<b>Lower of DEC-DEP Rate</b>
Schedule 1	\$ 55.00*	\$ 36.50	\$ 36.50
Schedule 3	\$ 38.00	\$ 47.52	\$ 38.00
Schedule 5	\$ 81.50	\$ 70.09	\$ 70.09
Schedule 6	\$ 81.50	\$ 50.09	\$ 50.09

\*DEC's Schedule 1 rate is based on the 2024 annual update

**Q. Will the Ancillary Services Adjustment apply to both legacy DEC and legacy DEP Joint OATT customers?**

A. Yes. Since both DEC and DEP Joint OATT customers would see an increase in Ancillary Service rates following the Internal Reorganization, we are offering a transitional

1 mitigation measure to both sets of customers. In addition, the Ancillary Services  
2 Adjustment will be offered to new OATT customers.

3 **Q. Why is it appropriate to limit the Ancillary Services Adjustment to two years?**

4 A. There are a number of reasons. First, because neither DEC nor DEP has filed to increase  
5 their respective ancillary services rates in many years, any increase in ancillary services  
6 rates will be driven as much by utilizing updated data inputs as by the Internal  
7 Reorganization itself. Second, during the two year stay-out, all Carolinas 1U OATT  
8 customers will get an affirmative benefit under the “lower of” approach because, by  
9 definition, they will pay either the same ancillary services rate that they pay today, or they  
10 will pay a lower rate, depending on the specific ancillary service schedule. Third, when  
11 the ancillary services rates are eventually updated, all Carolinas 1U customers will get the  
12 benefit of a lower operating reserve requirement resulting from the combined utility, which  
13 all else being equal, will result in lower rates compared to a two-utility scenario. Finally,  
14 unlike the Equalization Effect on Joint OATT rates, there is no similar impact on the rates  
15 for ancillary services because as noted above, the rates for these services are not  
16 consistently higher on either the DEC or DEP side.

17 **Q. When and if Carolinas 1U files to update its ancillary services rates, what standard  
18 of review will govern?**

19 A. I am not a lawyer, but it is my understanding that FERC will evaluate any such rate case  
20 under Federal Power Act section 205 to ensure that the updated ancillary services rates are  
21 just and reasonable and not unduly discriminatory.

1 **D. CONCLUSION AS TO THE OATT MITIGATION PLAN**

2 **Q. Taking a step back from the details, what are the biggest takeaways from the OATT**  
 3 **Mitigation Plan you describe above?**

4 A. The Internal Reorganization will allow Carolinas 1U to plan, execute, and operate a fully  
 5 integrated system. However, as is the case with most corporate reorganizations, certain  
 6 effects of combining two entities' rate structures would, if left unaddressed, result in  
 7 immediate cost reallocations for some subset of customers. Focusing on the impact to  
 8 legacy DEC and DEP Joint OATT customers, the three components of the OATT Mitigation  
 9 Plan appropriately and adequately address the rate impacts to legacy DEC and legacy DEP  
 10 Joint OATT customers that result from the Internal Reorganization.

11 To illustrate this point, Table 8 below includes legacy DEP and DEP Joint OATT  
 12 customer rates *without* the Equalization Adjustment and Divisor Adjustment, as well as the  
 13 rates resulting for Carolinas 1U (which reflect the two rate mitigators).

14 Table 8

<b>Forecasted 1U \$/MW-Month Rate</b>	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>	<b>Year 4</b>	<b>Year 5</b>
DEC \$/MW Month Rate (Non-merged)	2,753	3,110	3,571	4,134	4,648
DEP \$/MW Month Rate (Non-merged)	3,224	3,518	3,792	4,035	4,271
1U \$/MW-Month Rate Unadjusted (DEP)	2,885	3,205	3,574	3,988	4,371
1U \$/MW-Month Rate with Mitigation Adjustments* (DEC)	2,546	2,911	3,334	3,813	4,277

\* Includes both the Equalization Adjustment and Divisor Adjustment.

15 In sum, *with* the OATT Rate Mitigation Plan adjustments, the increases to legacy  
 16 DEC OATT rates are mitigated, and legacy DEP OATT customers also benefit from lower  
 17 ancillary services rates.

1 **IV. CONCLUSION**

2 **Q. Please summarize your testimony.**

3 A. The long-term benefits of the Internal Reorganization, with are discussed in great detail in  
4 the testimony of witness Peeler, far exceed any temporary cost reallocations impacting  
5 legacy DEC and DEP Joint OATT rates. The Companies' OATT Mitigation Plan  
6 implements three mitigation measures that appropriately address any potential cost shift  
7 impacts within the Joint OATT customer class—i.e., between legacy DEC and legacy DEP  
8 Joint OATT customers.

9 **Q. Does this conclude your testimony?**

10 A. Yes.

**Atkins Exhibit 1: Calculation of Equalization Effect**  
**DEP to DEC Cost Shift Calculation based on 2023 FF1 Data - DEC % Share**

<u>Line No.</u>		2024 Update <u>2023 FF1 Yr</u>
1	DEC Revenue Req't per Line 9 of Estimated File	\$ 452,867,961
2	DEC MW-Months per Line 17 of Estimated File x 12	<u>245,053</u>
3	DEC \$/MW-month (Line 1 ÷ Line 2)	\$ 1,848
4	DEP Revenue Req't per Line 8 of Filed Rate	\$ 322,634,599
5	DEP MW-Months per Line 9 of Filed Rate	<u>142,777</u>
6	DEP \$/MW-month (Line 4 ÷ Line 5)	\$ 2,260
7	Combined DEC & DEP Rev. Req.	\$ 775,502,559
8	Combined DEC & DEP MW-Months	<u>387,830</u>
9	Combined DEC & DEP \$/MW-month (Line 7 ÷ Line 8)	\$ 2,000
10	Increase in DEC Rate \$/MW-month (Line 9 - Line 3)	\$ 152
11	% Increase in DEC Rate \$/MW-month (Line 10 ÷ Line 3)	8%
12	Rev. Req. Cost Shift to DEC from DEP (Line 10 x Line 2)	\$ 37,138,559
13	Increase in DEC Rate \$/MW-month (Line 10)	\$ 152
14	DEC Billable MW for 2023	<u>55,148</u>
15	DEC Billing Impact (Line 13 x Line 14)	\$ 8,357,854
16	Percentage Share of Rev. Req. Adj. (Line 15 ÷ Line 12)	23%

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

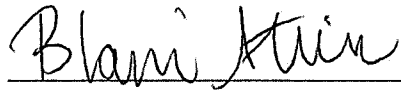
Duke Energy Corporation )  
Duke Energy Carolinas, LLC ) Docket No. EC25-\_\_\_-000  
Duke Energy Progress, LLC )

**PREPARED DIRECT TESTIMONY OF BLAIN ATKINS**

**VERIFICATION**


State of North Carolina )  
)

I, Blain Atkins, being first duly sworn, state that I am the witness identified in the foregoing prepared testimony, and that the statements of fact in the testimony are true and correct to the best of my knowledge, information, and belief.

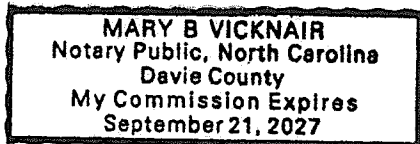
  
\_\_\_\_\_  
Blain Atkins

SUBSCRIBED AND SWORN before me

the 1 day of August, 2025

  
\_\_\_\_\_  
Notary Public

My commission expires on: 09/21/2027



**Attachment 4**

**Affidavit and Supporting Materials of Ms. Julie R. Solomon**

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

<b>Duke Energy Corporation</b>	)	
<b>Duke Energy Carolinas, LLC</b>	)	<b>Docket No. EC25-__-000</b>
<b>Duke Energy Progress, LLC</b>	)	

**AFFIDAVIT OF JULIE R. SOLOMON**

**I. INTRODUCTION**

My name is Julie R. Solomon. I am a Managing Director at Secretariat LLC (“Secretariat”), an economic consulting firm located at 2121 K Street, NW, Washington, DC. A large portion of my consulting activities involves electric utility industry restructuring and the transition from regulation to competition. I have been involved extensively in consulting on market power issues concerning mergers, other asset transactions, and market-based rate applications. I often file affidavits before the Federal Energy Regulatory Commission (“Commission” or “FERC”) in connection with electric utility mergers, the purchase and sale of jurisdictional assets, applications for market-based rates, and triennial updates. My resume is included as Exhibit SEC-1.

Duke Energy Corporation (“Duke Energy” or “Duke”) is seeking Commission authorization pursuant to Federal Power Act (“FPA”) section 203 for an internal reorganization involving Duke Energy Carolinas, LLC (“DEC”) and Duke Energy Progress, LLC (“DEP”) (collectively with Duke Energy, “Applicants”). Specifically, the Applicants plan to consolidate DEC and DEP into a single operating company with the combined surviving entity serving all retail customers in the legacy DEC and legacy DEP service territories in North Carolina and South Carolina, as well as existing wholesale customers of DEC and DEP (“Internal Reorganization”). Although not an event that is itself subject to Commission approval pursuant to FPA section 203, I understand that commensurate with the Internal Reorganization, Duke also plans to merge its three existing balancing authority areas (“BAAs”) in the Carolinas – the Duke Energy Carolina (“DUK”) BAA, the Duke Energy

Progress East (“CPLE”) BAA, and the Duke Energy Progress West (“CPLW”) BAA (collectively, “Legacy BAAs”) – into a single “Combined DUKE BAA” (“BAA Consolidation”).<sup>1</sup>

## II. SUMMARY

Counsel for Duke has asked me to address the proposed Internal Reorganization and the BAA Consolidation from the perspective of competitive effects. The Commission’s standard of review for section 203 applications requires applicants to address, among other factors, any “adverse impacts” on competition. Within the competition analysis, FERC requires applicants to address horizontal and vertical competitive impacts.

Internal reorganizations such as this one are a special class of transactions that do not generally raise the possibility of adverse competitive issues. That is because FERC already considers two affiliated companies to be a single “seller” for purposes of all its competitive analyses. Under Commission regulations and precedent, a horizontal Competitive Analysis Screen (a/k/a a Delivered Price Test or “DPT”) is not required for internal reorganizations that are not true change-in-control transactions.<sup>2</sup> Consequently, a DPT would necessarily show no change in market concentration resulting from such an internal reorganization. Thus, no traditional competitive analysis is required to demonstrate the Internal Reorganization’s lack of impact. Consistent with this approach, the Commission has already considered DEC and DEP to be effectively combined since the merger of the Duke Energy and Progress Energy holding companies in 2012. Stated another way, the proposed Internal Reorganization (i.e., the consolidation of DEP and DEC into a single operating company) will not have any direct impact on competition because it will not result in any change in control over generation, and the Commission has evaluated DEP and DEC jointly for market power purposes

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<sup>1</sup> These BAAs are sometimes more recently referred to as the Duke Energy Carolinas (“DEC”) BAA; the Duke Energy Progress East (“DEP-East”) BAA; and the Duke Energy Progress West (“DEP-West”) BAA. Here, I use the existing BAA acronyms that the Commission identifies in its MBR database.

<sup>2</sup> See 18 C.F.R. § 33.3(a)(1). In Docket No. EC13-113, NV Energy, Sierra Pacific Power Company, and Nevada Power Company sought Commission approval for an internal corporate reorganization that was proposed to take place as the companies were combining of the formerly separate Nevada Power Company and Sierra Pacific Power Company BAAs. While an analysis of the effect of combining BAAs was submitted to the Commission in that proceeding, the Commission concluded that FERC “regulations do not require Applicants to file such an analysis in connection with an internal corporate reorganization such as the Proposed Transaction” and, therefore, the Commission made no findings with respect to the competitive analysis. *NV Energy, Inc.*, 145 FERC 61,170, at P 26 (2013) (“NV Energy Order”).

since their respective holding companies merged in 2012. The Commission undertook its full competitive analysis of the combination of DEP and DEC at that time.

### **III. BACKGROUND**

The Duke-Progress holding company merger was conditionally approved by the Commission in 2011.<sup>3</sup> Since Duke Energy and Progress Energy were, at that time, unaffiliated entities proposing to combine, the parties to that transaction submitted a section 203 application to seek approval for the combination. In that 2011 application, the full required horizontal and vertical competitive analysis was undertaken to measure the impact in the market of “combining” what is now DEC and DEP. This detailed analysis was undertaken at that time irrespective of the fact that the companies were planning to maintain DEC and DEP as separate operating companies because, as I explained above, FERC policy considered them to be a single “seller” in the market. In other words, even though the 2012 merger was only a merger of holding companies, FERC’s analysis in 2011 was focused on the assumed combination of DEC and DEP (because the holding companies themselves owned no utility assets and served no customers).

In that proceeding, the Commission determined that the assumed combination of DEC and DEP caused a horizontal screen failure (in a single time period within a single season) that required a form of “mitigation.” The mitigation measure focused primarily on the interface between the “DUK” and “CPL” Balancing Authority Areas. FERC conditioned its approval on a commitment by the applicants to “establish a transmission set-aside of 25 MW of firm transmission capacity between DUK and CPL for use by third parties.<sup>4</sup> The general purpose of the set-aside was to ensure that the Duke entities’ use of that interface would not obstruct the ability of third-party loads to reach competing resources in the other BAA. This so-called “Stub Mitigation,” was deemed sufficient to remedy the remaining “screen failure.” This commitment and set-aside was applicable only for one seasonal period, the Summer Off-Peak season/load period. In 2014, based on updated facts, two changes were made: (i) the transmission set-aside was increased from 25 MW to 129 MW; and (ii) Applicants committed to operating certain phase angle regulators (“PARs”) to eliminate overloads and increase Available Transmission Capacity (“ATC”) into the CPL BAA. The independent

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<sup>3</sup> *Duke Energy Corporation*, 136 FERC ¶ 61,245 (2011) (“Merger Order”).

<sup>4</sup> *Duke Energy Corporation*, 139 FERC ¶ 61,194 (2011) (“Order Accepting Revised Compliance Filing”).

monitoring of the transmission set-aside requirement and the PARs operation was undertaken by Potomac Economics, with annual reporting in the Duke/Progress Merger docket.<sup>5</sup> As explained in the application my affidavit supports, after the Internal Reorganization, the Stub Mitigation will no longer be necessary since parties serving load in these legacy BAAs will no longer be required to reserve point-to-point transmission between these legacy BAAs; in other words, there will be no transmission cost to deliver power anywhere within the combined BAA.

#### **IV. PRO-COMPETITIVE EFFECTS OF COMBINING THE THREE LEGACY BAAs**

As I explained above, the Internal Reorganization itself per se has no impact, adverse or otherwise, on competition. However, I understand that, as part of the companies' efforts to achieve customer savings under the Internal Reorganization, they also have decided to combine the three Legacy BAAs into a single Combined DUKE BAA. As a result, I was asked to opine on the competitive impact of the BAA consolidation out of an abundance of caution and for completeness of the record. I will explain here why consolidation of three BAAs into one is inherently pro-competitive and certainly has no adverse impact on customers.

##### **1. Creation of a Single Larger "Market"**

The first and most immediate impact of combining three BAAs into one is that it creates a larger relevant geographic market. All generation supplies within the three legacy BAAs will now be in a single "market" for study purposes. This matters most when it comes to transmission access. If a load-serving entity in one Legacy BAA today sought to source supply in another one of the three Legacy Duke Energy BAAs, it would have to separately reserve and pay for point-to-point transmission service. A single BAA acts as a single market with no internal point-to-point service required to reach that supply currently sitting in another Legacy BAA.

As shown in Table 3 below, the combination of the Legacy BAAs into a combined single DUKE BAA will increase the overall supply in the combined BAA.<sup>6</sup> While this is a simplified

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<sup>5</sup> *Duke Energy Corporation*, 149 FERC ¶ 61,078 (2014) ("Stub Mitigation and Phase Shifter Order"). The Phase Shifters refer to the Rockingham phase angle regulators (PARS).

<sup>6</sup> Note that in reporting MWs in the various tables herein, the summer/winter ratings for generation are relied on, with the exception of renewables, which are based on capacity adjusted for availability (i.e., historical capacity factor).

analysis of gross installed capacity, the basic point is that the creation of a single larger market makes more generation accessible to load.

**Table 1: Total Supply in Combined DUKE BAA and Legacy BAAs<sup>7,8</sup>**

Stand-Alone BAAs and Combined BAA (MWs)					Increase Relative to Standalone (MWs)		
Season	DUK	CPLW	CPLW	Combined Total	DUK	CPLW	CPLW
Summer	24,619	15,214	1,133	40,966	16,347	25,752	39,833
Winter	25,604	14,844	1,244	41,692	16,088	26,848	40,448

Even if I account for load obligations (under the forecasted peak-load conditions), the total internal available generation supply within a combined DUKE BAA is greater than each legacy BAAs.

**Table 2: Available Supply (after Accounting for Peak Load)<sup>9</sup> within Combined DUKE and Standalone BAAs**

Stand-Alone BAAs and Combined BAA (MWs)					Increase Relative to Standalone (MWs)		
Season	DUK	CPLW	CPLW	Combined Total	DUK	CPLW	CPLW
Summer	4,451	1,514	236	6,200	1,750	4,686	5,965
Winter	4,771	1,818	124	6,713	1,942	4,895	6,589

## 2. Increase in “First-Tier” Supplies

The second relevant effect of combining the BAAs for purposes of a competition analysis is the fact that the new larger market increases the amount of supply from neighboring areas that will only be one transmission “wheel” away from the load. In FERC market power parlance, this is referred to as “first-tier” supply. Increases in first-tier supply are generally pro-competitive because for wholesale customers within the newly-consolidated single DUKE BAA, it increases the amount of generation from neighboring areas that could be easily delivered to load and thus compete with Duke to supply that load.

<sup>7</sup> The Shoulder Season (i.e., Spring and Fall) would be approximated by the average of Winter and Summer ratings reported in relevant tables.

<sup>8</sup> Data are based on Hitachi Velocity Suite generation data.

<sup>9</sup> Data on generation unit data and adjustments for availability for wind and solar are based on Hitachi Velocity Suite; and peak load data are based on FERC Form 714, EIA Form 930 and EIA-861.

To quantify that effect, I measured the amount of generation that is available in these first-tier areas and compared it to the amount of first-tier supply to each of the three separate Legacy BAAs as they exist today. For purposes of my analysis, the scope of the relevant geographic markets includes the Combined DUKE BAA after the BAA Consolidation and the Legacy DUK, CPLE and CPLW BAAs as currently configured, plus first-tier markets that include Dominion Energy South Carolina, Inc. (“DESC”), Santee Cooper (“SC”), Southern Company Services, Inc. (“SOCO”), Tennessee Valley Authority (“TVA”), PJM Interconnection, LLC (“PJM”) and Southeastern Power Administration (“SEPA”). Loads in legacy CPLE and CPLW will gain new first-tier interconnections to multiple adjacent BAAs, including Southern Company, Southeastern Power Administration, Santee Cooper and Dominion Energy South Carolina.

Table 3 below identifies which BAAs are first-tier to the legacy DUK, CPLE and CPLW BAAs (respectively), and indicates that each of the BAAs will be first-tier to the Combined DUKE BAA. Following Table 3, Figure 1 provides an excerpt of the Commission’s balancing authority “map” that reflects the relevant interconnections.<sup>10</sup>

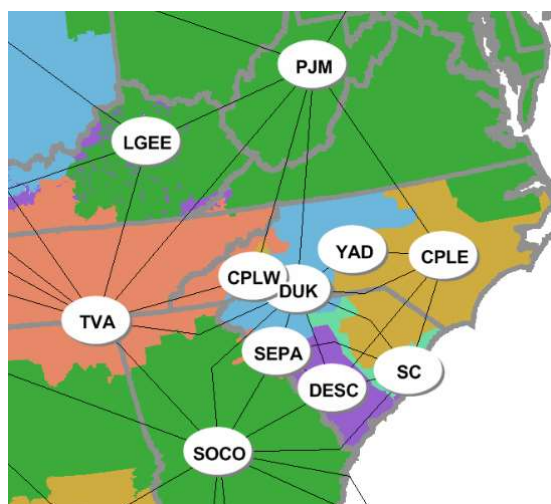
**Table 3: BAAs First-Tier to Legacy BAAs<sup>11</sup>**

<b>BAA</b>	<b>DUK</b>	<b>CPLE</b>	<b>CPLW</b>	<b>COMBINED</b>
Dominion Energy South Carolina (DESC)	x	x		x
Santee Cooper (SC)	x	x		x
Southern Company (SOCO)	x			x
Tennessee Valley Authority (TVA)	x		x	x
PJM Interconnection LLC (PJM)	x	x	x	x
Southeastern Power Administration	x			x

<sup>10</sup> Note that I did not include the Yadkin, Inc. (“YAD”) in my analysis, although it is reflected in the BAA map in Figure 1. YAD is a very small BAA, in which Cube Hydro Carolinas owns and operates four hydroelectric plants (~ 200 MW) and transmission lines that comprise the Yadkin BAA.

<sup>11</sup> Data are based on FERC Form 714.

**Figure 1: Excerpt from the Map of Balancing Authorities (as of October 2019)<sup>12</sup>**



The combination of the Legacy BAAs into a combined single DUKE BAA will have a beneficial effect on potential supply into CPLE and CPLW. Table 4 below identifies first-tier BAAs for each of the legacy and combined DUKE BAAs. The table shows that the number of first-tier interconnections to combined DUKE BAA will be greater than the number of first-tier interconnections to CPLE and CPLW stand-alone BAAs. For example, only the current stand-alone DUK BAA is directly interconnected to SOCO; whereas CPLE and CPLW currently are second-tier to SOCO, and the combined DUKE BAA will be first-tier to SOCO after the Internal Reorganization and BAA Consolidation. Similarly, Duke and CPLW are first-tier to TVA but CPLE is second-tier to TVA; the combined DUKE BAA will result in CPLE being first-tier to TVA. In fact, as is shown in Table 2 below, the Combined BAA will be first-tier to each of PJM, SC, DESC, SEPA, SOCO and TVA. This creates a larger set of markets first-tier to the existing CPLE and CPLW. PJM is the only BAA that is first-tier to each of the Legacy BAAs.

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<sup>12</sup> <https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx>. “NERC Balancing Authority Areas (As of October 2019)”

**Table 4: Relevant BAAs First- and Second-Tier to Legacy BAAs <sup>13</sup>**

BAA	Name	Legacy BAAs			Combined BAA	Removing an Additional Wheel
		DUK	CPLW	CPLW		
CPLW	Progress Energy Carolina East	1	0	2	0	↓
CPLW	Progress Energy Carolina West	1	2	0	0	↓
DUK	Duke Energy Carolinas LLC	0	1	1	0	↓
PJM	PJM Interconnection	1	1	1	1	↓
SC	Santee Cooper	1	1	2	1	↓
DESC	Dominion Energy South Carolina	1	1	2	1	↓
SEPA	Southeastern Power Administration	1	2	2	1	↓
SOCO	Southern Company	1	2	2	1	↓
TVA	Tennessee Valley Authority	1	2	1	1	↓

### 3. No Adverse Effect on Vertical Market Power

I will briefly address why there are no vertical market power concerns arising from this Internal Reorganization. Vertical market power analysis considers whether there is a new combination of existing entities that provide inputs to electricity products or any new entities that provide generation products. Again, the Commission has already held that the assumed combination of DEC and DEP has no vertical market power concerns.

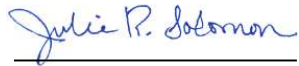
## V. CONCLUSION

The proposed Internal Reorganization (i.e., the consolidation of DEP and DEC into a single operating company) will not have any direct impact on competition because it will not result in any change in control over generation, and the Commission has evaluated DEP and DEC jointly for market power purposes since their respective holding companies merged in 2012. In addition, the analyses discussed herein support the conclusion that the BAA Consolidation will not have adverse competitive effects in the relevant markets.

<sup>13</sup> See note 11.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed the 11<sup>th</sup> day of August 2025.

A handwritten signature in blue ink that reads "Julie R. Solomon". The signature is written in a cursive style and is positioned above a horizontal line.

Julie R. Solomon

**Attachment 5**  
**Accounting Entries**

**Duke Energy Progress**  
**Proposed CAR1U Accounting Entries**

Beginning with the 2027 reporting period, Duke Energy Carolinas ("DEC"), as the surviving entity of the merger, anticipates filing a consolidated annual FERC Form No. 1 and quarterly 3-Qs that will reflect singular account balances for the combined post-merger utility. As such, DEC will assume all assets, liabilities and capitalization amounts of Duke Energy Progress's ("DEP") December 31, 2026 balance sheet. Below are the expected accounting entries on January 1, 2027 using the December 31, 2024 FERC account balances for illustration purposes only.

Line No	Entry No	FERC Account	FERC Account Description	Debit	Credit
1	1.		To settle inter-company payable balances at DEP that are owed to DEC as of December 31, 2026 <sup>3</sup> prior to transferring DEP's balance sheet to DEC. Entry to be recorded on January 1, 2027. Note, this entry reflects the entry to the DEC balance sheet.		
2					
3		131.0	Cash	\$ 132,907,823	
4		146.0	Accounts Receivable from associated companies		\$ 132,907,823
5					
6	2.		To record the transfer of DEP's balance sheet as of December 31, 2026 <sup>4</sup> to DEC. Entry to be recorded on January 1, 2027. Note, this entry reflects entries to the DEC balance sheet.		
7					
8		101.0	Electric Plant in Service	\$ 34,063,464,089	
9		101.1	Property, Plant and Equipment Cost	\$ 1,117,676,117	
10		105.0	Electric Plant Held for Future Use	\$ 58,464,115	
11		106.0	Completed construction not classified-Electric	\$ 3,382,084,526	
12		107.0	Construction work in progress-Electric	\$ 1,882,795,486	
13		108	Accumulated provision for depreciation of electric utility plant		\$ 15,359,432,695
14		111	Accumulated provision for amortization of electric utility plant		\$ 413,505,895
15		114.0	Electric Plant Acquisition Adjustments	\$ 349,801,943	
16		115.0	Property, Plant and Equipment - Accumulated depreciation and amortization		\$ 120,144,740
17		120.1	Nuclear fuel in process of refinement, conversion, enrichment and fabrication	\$ 349,645,107	
18		120.3	Nuclear fuel assemblies in reactor	\$ 787,475,300	
19		120.4	Spent Nuclear Fuel	\$ 378,000,585	
20		120.5	Accumulated provision for amortization of nuclear fuel assemblies		\$ 813,896,836
21		121	Nonutility Property	\$ 37,928,365	
22		122	Accumulated provision for depreciation and amortization of nonutility property		\$ 13,853,388
23		123.1	Investment in Subsidiary Companies	\$ 28,464,276	
24		124	Other Investments	\$ 48,405,118	
25		128	Other special funds	\$ 4,996,936,389	
26		141	Notes receivable	\$ 886,826	
27		131	Cash		\$ 996,393
28		142	Customer accounts receivable	\$ 587,731,091	
29		143	Other accounts receivable	\$ 234,729,252	
30		144	Accumulated provision for uncollectible accounts—credit		\$ 44,187,456
31		145	Notes receivable from associated companies	\$ 3,848,135	
32		146	Accounts receivable from associated companies	\$ 2,283,347	
33		151	Fuel stock	\$ 267,234,886	
34		154	Plant materials and operating supplies	\$ 1,028,162,776	
35		156	Other materials and supplies		\$ 58,206
36		158.1	Allowances	\$ 138,137,748	
37		163	Stores expense undistributed	\$ 45,458,250	
38		165	Prepayments	\$ 94,978,467	
39		172	Rents receivable	\$ 81,664	
40		173	Accrued utility revenues	\$ 206,858,390	
41		174	Miscellaneous current and accrued assets		\$ 696,793
42		175	Derivative instrument assets	\$ 60,020,493	
43		176	Derivative instrument assets-Hedges	\$ 17,559,059	
44		181	Unamortized debt expense	\$ 56,980,277	
45		182.2	Unrecovered plant and regulatory study costs	\$ 125,932,224	
46		182.3	Other regulatory assets	\$ 4,144,025,777	
47		183	Preliminary survey and investigation charges	\$ 9,928,142	
48		184	Clearing accounts	\$ 86,995	
49		186	Miscellaneous deferred debits	\$ 371,895,695	
50		189	Unamortized loss on reacquired debt	\$ 209,385	
51		190	Accumulated deferred income taxes		\$ 2,222,132,003
52		211	Miscellaneous paid-in capital		\$ 2,784,302,138
53		215.1	Appropriated retained earnings—Amortization reserve, Federal		\$ 11,261,035
54		216	Unappropriated retained earnings		\$ 9,458,447,120
55		216.1	Unappropriated undistributed subsidiary earnings	\$ 276,459,780	
56		219	Accumulated other comprehensive income	\$ 10,986	

**Duke Energy Progress**  
**Proposed CAR1U Accounting Entries**

57	221	Bonds		\$	10,475,185,000
58	223	Advances from associated companies.		\$	150,000,000
59	224	Other long-term debt		\$	585,000,100
60	226	Unamortized discount on long-term debt—Debit	\$	24,000,736	
61	227	Obligations under capital lease—noncurrent		\$	806,125,526
62	228.2	Accumulated provision for injuries and damages		\$	2,381,711
63	228.3	Accumulated provision for pensions and benefits		\$	129,866,489
64	228.4	Accumulated miscellaneous operating provisions		\$	13,639,211
65	230	Asset retirement obligations		\$	4,334,256,585
66	232	Accounts payable		\$	772,626,308
67	233	Notes payable to associated companies		\$	610,990,000
68	234	Accounts payable to associated companies		\$	362,343,709
69	235	Customer deposits		\$	117,518,863
70	236	Taxes accrued		\$	173,883,903
71	237	Interest accrued		\$	121,790,727
72	241	Tax collections payable		\$	18,661,172
73	242	Miscellaneous current and accrued liabilities		\$	315,447,698
74	243	Obligations under capital leases—current		\$	82,205,836
75	244	Derivatives instrument liabilities		\$	550,065
76	245	Derivative instrument liabilities-Hedges		\$	25,209,518
77	252	Customer advances for construction		\$	6,358,470
78	255	Accumulated deferred investment tax credits		\$	143,884,818
79	253	Other deferred credits		\$	91,788,043
80	254	Other regulatory liabilities.		\$	4,291,007,609
81	282	Accumulated deferred income taxes—Other property		\$	2,944,950,882
82	283	Accumulated deferred income taxes—Other		\$	1,804,318,863

83  
84 Footnotes:

<sup>1</sup> The balances presented above are from the December 31, 2024 filed 2024 DEP FERC Form 1. The actual entries to be recorded effective January 1, 2027 will be based on balances as of December 31, 2026, which will be shown in the 2026 DEP FERC Form 1.

85

**Attachment 6**  
**Verification**

UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION

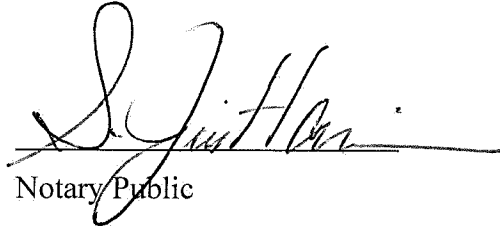
VERIFICATION PURSUANT TO 18 C.F.R. § 33.7

V. Nelson Peeler, Jr. verifies under penalty of perjury that he is Senior Vice President, Grid Strategy, Planning and Integration for Duke Energy Corporation and has read the enclosed application and, to the best of his knowledge, information and belief, all of the statements contained therein with respect the matters described therein are true and correct.

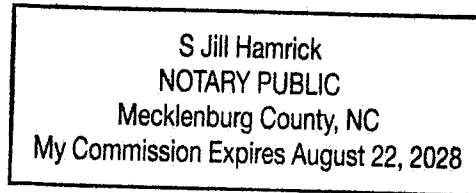


V. Nelson Peeler, Jr.  
Senior Vice President, Grid Strategy, Planning  
and Integration  
Duke Energy

SUBSCRIBED AND SWORN before me  
the 5 day of August, 2025.



Notary Public



My commission expires on: 2/22/2028

PLEASE JOIN US FOR A  
**TEA PARTY**



TO CELEBRATE  
**WESTMINSTER'S 150TH BIRTHDAY**  
Bring your favorite tea cup- optional

4th OCTOBER 2025 AT 2PM  
MARTIN HOUSE  
510 E MAIN ST. WESTMINSTER

RESERVE TICKET BY SEPTEMBER 18TH  
\$10 PER PERSON ONLINE  
OR CHECKS TO  
LDGC, PO BOX 155, WESTMINSTER

FUNDS RAISED FOR WEST-OAK SCHOLARSHIP