



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

June 19, 2026

GENERAL INFORMATION

Historic Building Survey

When SCDOT demolished the old Highway 76 bridge, it entered into an agreement with the South Carolina Department of Archives and History to document and catalog Westminster's historic buildings. As part of that effort, New South Associates was retained to conduct historical research and prepare the necessary documentation.

New South has completed a significant amount of research and is now seeking input from the public to determine whether residents may have additional information, photographs, stories, or other historical resources that could enhance the project or provide leads for further research. The focus of the study is on buildings constructed prior to 1976, and the consultants are particularly interested in learning more about the history, ownership, and significance of those structures.

Representatives from New South Associates will speak at the Westminster Rotary Club meeting on July 7 and will also host a public meeting later that evening. Please see the attached information for meeting details.

If you know individuals who may have historical knowledge of Westminster, family records, photographs, or information related to buildings constructed before 1976, please share this information with them and encouraging them to attend.

As a final note, the City of Westminster is not funding any portion of this project. The work is being funded entirely by the State of South Carolina as part of the bridge replacement process.

Squeal on Pigs!

Squeal on Pigs! is a public awareness and reporting campaign designed to help track and manage feral swine populations across the United States and Canada. Feral hogs are an invasive species that cause significant damage to agriculture, natural resources, property, and wildlife habitat while also posing risks to animal and human health. The program encourages the public to report sightings through its website and mobile app, providing valuable data to wildlife managers and researchers. Sighting reports help agencies better understand feral swine populations and develop effective management strategies to reduce their impacts. The initiative is supported by the USDA Animal and Plant Health Inspection Service (APHIS), the University of Georgia, and other conservation partners.

More information and mobile app information available at: <https://squealonpigs.com/>

The William Bartram Statue Project

Tapping into the network of enthusiasts who appreciate the legacy of William Bartram is an important component—and a compelling reason—for creating a lasting tribute to Bartram in downtown Westminster. City staff secured Oconee County Accommodations Tax funding as well as a donation from the Westminster Lazy Dasiey Garden Club to commence the development of a standalone website for the project. The web site development is expected to be completed in July.

Downtown Streetscape Update

Main St is nearly at final grade. The retaining wall contractor will be done by end of next week. Sidewalk demolition will begin on the Lucky St portion next week. The most recent schedule is attached.

The streetscape project is paid for with a combination of Community Development Block Grant, Appalachian Regional Commission Grant and Oconee County C-Funds.

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

- Our 8u, 10u, 12u, & 15u softball team are currently in North Augusta participating in the South Carolina Athletic Programs State Tournament.
- Our 10u all star baseball team will be participating in the Diamond Youth Baseball Tournament in July.
- Fall sports registration is being held until June 26. Fall sports include baseball, softball, soccer, football, cheerleading, and volleyball. In person registration will be held next week.
- Lunches continue to be provided by the SDOC on weekdays. Lunches will be served 11:30 am – 12:30 pm. They must be eaten on site.
- We are planning our first travel baseball tournament of the summer on July 4-5. Details of the event will be shared once they are finalized.

Horton Outdoor Recreational Area

Ribbon cutting to be scheduled – likely for August 2026.

Lucky Street, James Street, and Highland Avenue Water Improvements

Notice to Proceed was issued March 25, 2026. Construction schedule details 90 days to Substantial Completion, 105 days to Final Completion. Lucky St Water Main is 100% complete. Mimosa St Extension Water Main install is completed as well. James St & Highland Ave are set to begin on June 29th pending no delays.

Electric Undergrounding Project

UPA has completed all boring. Pads have been set. 100% of the wire has been pulled. 80% of terminations have been made. Waiting for delivery of switchgear.

SCADA Upgrade Project

The Notice to Proceed was issued March 26, 2026. The project schedule details 150 Days to Substantial Completion, 180 Days to final completion. The radio survey has been completed with excellent results. The design is in development, and radio delivery is expected in the second week of July. (*No Updates*)

Unity Tank Upgrade

The Unity Tank project is being funded through the South Carolina Rural Infrastructure Authority (SC RIA) and the City's 2025 Combined Utility System Bond. The DES construction permit has been approved, and the project will be ready for bids soon.

Oconee Economic Alliance (OEA)

The OEA met Friday, June 19, 2026; the agenda is attached.

Board of Zoning Appeals

Nothing to report.

Westminster Planning Commission

Nothing to report.

OJRSA

Past and future meetings are available on OJRSA's YouTube channel:

<https://www.youtube.com/@OconeeJRSA>

PMPA

The PMPA Board met Thursday, June 18, 2026 at 10:00 am; the agenda is attached.

PLEASE MARK YOUR CALENDAR

July 3, 2026 City Offices Closed in Observance of Independence Day

Special Events Calendar

South Carolina Apple Festival – September 3-5, 2026 Downtown Westminster

Read more about the festival here: <https://visitoconeesc.com/sc-apple-festival/>

South Carolina Bigfoot Festival – October 9-10, 2026 Downtown Westminster

For more information: <https://www.scbigfootfestival.com/schedule>

Veterans Day Parade – November 11, 2026

Time TBD. Main Street, Westminster.

Christmas Parade – December 4, 2026

Time TBD. Main Street, Westminster.

Join Us!

WESTMINSTER SC

City of Westminster
Historic Building Survey

LOCATION

Westminster Depot
(129 E. Main Street)

Tuesday, July 7th

Starting at
5:30PM

The City of Westminster and New South Associates are working together to **identify and record historic buildings and sites** within the community.



*homes, churches,
cemeteries,
businesses,*

*parks,
neighborhoods*

built before 1976

We are hosting a public meeting to provide information about the project and the survey process. Westminster residents are invited to attend, ask questions, and share information and stories about the town's history.

We would love to hear from you and hope you join us!





OCONEE ECONOMIC ALLIANCE

OCONEE COUNTY, SOUTH CAROLINA, USA

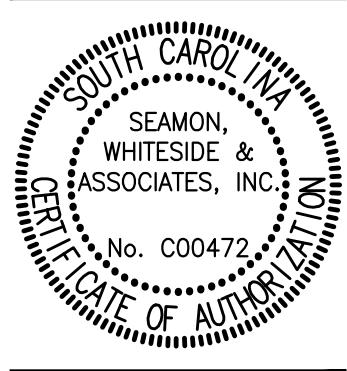
Board of Directors Meeting June 19, 2026

- I. Welcome and Introductions**
- II. Invocation**
- III. April 2026 OEA Board of Directors Meeting Minutes**
- IV. April/May 2026 OEA Financial Report**
- V. OEA Economic Development Report**
 - ✓ **Project Activity**
 - ✓ **Inquiries, Leads and Prospects**
 - ✓ **Business Retention and Engagement (BRE)**
 - ✓ **Marketing**
 - ✓ **Product Development**
 - ✓ **Operations**
- VI. OEA Board of Directors Investor Spotlight**
 - ✓ **Think Oconee Relaunch**
Dari McBride, President, Oconee Chamber of Commerce
- VII. Board Discussion**
- VIII. Adjourn**

501 WINDSOR PARK BOULEVARD, SUITE 200 | MOUNT PLEASANT, SC 29564 | JUDSON HALL BUILDING 6008 7th FLOOR | GREENVILLE, SC 29611 | 230 PETERSBORO | CHARLOTTE, NC 28217 | 701 N. GEMAS STREET | SUMMERVILLE, SC 29586 | 101 N. DANIEL MORGAN AVENUE SUITE 300 | SPARTANBURG, SC 29306
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MOUNT PLEASANT, SC 843.884.1667
 GREENVILLE, SC 864.298.0534
 SUMMERVILLE, SC 843.972.0710
 SPARTANBURG, SC 864.272.1272
 CHARLOTTE, NC 980.312.5450
 WWW.SEAMONWHITESIDE.COM



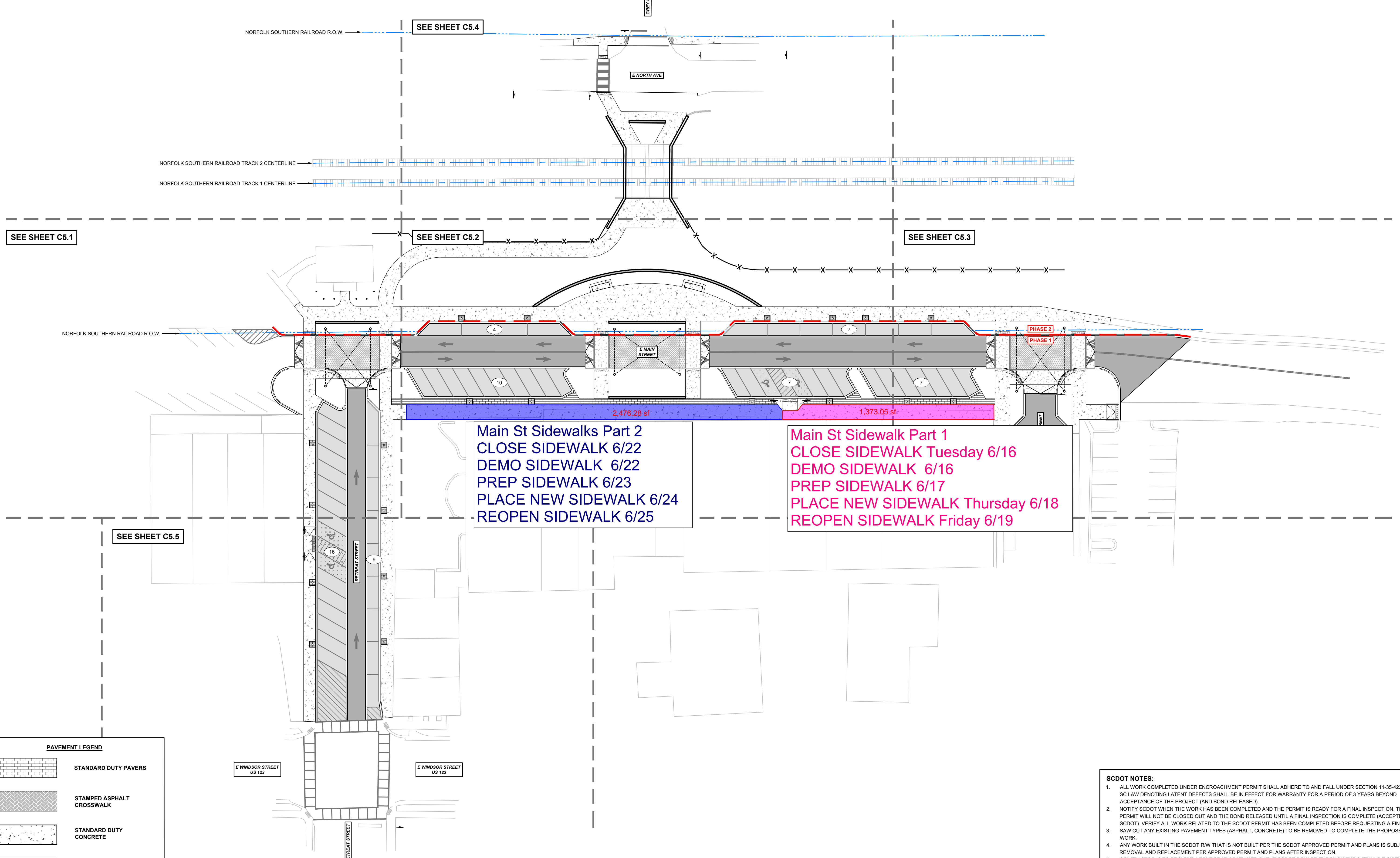
WESTMINSTER DOWNTOWN
IMPROVEMENTS - PHASE 1 & PHASE 2
 WESTMINSTER, SOUTH CAROLINA

SW+ PROJECT: 10624
 DATE: 08/13/2025
 DRAWN BY: NH / AC
 CHECKED BY: WB / DM

REVISION HISTORY	
0	IFC
1	ADD#2
2	REV 2
3	REV 3

SITE PLAN (OVERALL)

C5.0



Main St Sidewalks Part 2
 CLOSE SIDEWALK 6/22
 DEMO SIDEWALK 6/22
 PREP SIDEWALK 6/23
 PLACE NEW SIDEWALK 6/24
 REOPEN SIDEWALK 6/25

Main St Sidewalk Part 1
 CLOSE SIDEWALK Tuesday 6/16
 DEMO SIDEWALK 6/16
 PREP SIDEWALK 6/17
 PLACE NEW SIDEWALK Thursday 6/18
 REOPEN SIDEWALK Friday 6/19

PAVEMENT LEGEND	
	STANDARD DUTY PAVERS
	STAMPED ASPHALT CROSSWALK
	STANDARD DUTY CONCRETE
	ADA CONCRETE
	HEAVY DUTY ASPHALT
	STANDARD DUTY ASPHALT
	SCDOT ASPHALT
	HEAVY DUTY CONCRETE

PARKING TABLE	
48	EXISTING PARKING PRIOR TO IMPROVEMENTS ± 48 SPACES
60	PROPOSED PARKING POST IMPROVEMENTS 60 SPACES
12	NET PARKING GAIN / LOSS ± 12 SPACE GAIN

LINE LEGEND	
	PHASE LINE PHASE 1 - PLAN SOUTH / PHASE 2 - PLAN NORTH

SURVEY NOTE:
 1. BOUNDARY AND ALL ELEVATIONS ARE BASED ON THE TOPOGRAPHIC SURVEY COMPLETED BY **STEPHEN R. EDWARDS & ASSOCIATES**, RECEIVED **SEPTEMBER 29, 2023**. THE VERTICAL ELEVATION DATUM IS NORTH AMERICAN VERTICAL DATUM OF 1988 (NAVD88) AND THE HORIZONTAL DATUM IS NAD83. SITE IS LOCATED AT EAST MAIN STREET IN THE CITY OF WESTMINSTER, SOUTH CAROLINA.

EXISTING UTILITY NOTE:
 THE LOCATION OF EXISTING UNDERGROUND UTILITIES ARE SHOWN IN AN APPROXIMATE WAY ONLY AND HAVE NOT BEEN INDEPENDENTLY VERIFIED BY THE OWNER OR ITS REPRESENTATIVE. THE CONTRACTOR SHALL DETERMINE THE EXACT LOCATION OF ALL EXISTING UTILITIES BEFORE COMMENCING ANY WORK, AND AGREES TO BE FULLY RESPONSIBLE FOR ANY AND ALL DAMAGES WHICH MIGHT OCCUR DUE TO THE CONTRACTOR'S FAILURE TO EXACTLY LOCATE AND PRESERVE ANY AND ALL UNDERGROUND UTILITIES.

- SCDOT NOTES:**
- ALL WORK COMPLETED UNDER ENCROACHMENT PERMIT SHALL ADHERE TO AND FALL UNDER SECTION 11-35-4230 OF SC LAW DENOTING LATENT DEFECTS SHALL BE IN EFFECT FOR WARRANTY FOR A PERIOD OF 3 YEARS BEYOND ACCEPTANCE OF THE PROJECT (AND BOND RELEASED).
 - NOTIFY SCDOT WHEN THE WORK HAS BEEN COMPLETED AND THE PERMIT IS READY FOR A FINAL INSPECTION. THE PERMIT WILL NOT BE CLOSED OUT AND THE BOND RELEASED UNTIL A FINAL INSPECTION IS COMPLETE (ACCEPTED BY SCDOT). VERIFY ALL WORK RELATED TO THE SCDOT PERMIT HAS BEEN COMPLETED BEFORE REQUESTING A FINAL SAW CUT ANY EXISTING PAVEMENT TYPES (ASPHALT, CONCRETE) TO BE REMOVED TO COMPLETE THE PROPOSED WORK.
 - ANY WORK BUILT IN THE SCDOT R/W THAT IS NOT BUILT PER THE SCDOT APPROVED PERMIT AND PLANS IS SUBJECT TO REMOVAL AND REPLACEMENT PER APPROVED PERMIT AND PLANS AFTER INSPECTION.
 - CONTRACTOR IS TO PROVIDE A TEMPORARY PATH WITHIN THE SCDOT ROW OR THROUGH THE SITE WHILE SIDEWALK IS CLOSED. CONTRACTOR IS TO LEAVE THE EXISTING SIDEWALK IN PLACE FOR AS LONG AS POSSIBLE AND REPLACE THE SIDEWALK AS QUICKLY AS POSSIBLE, SO THE SIDEWALK IS CLOSED FOR A MINIMAL AMOUNT OF TIME.

Know what's below. Call before you dig.
 SCALE: 1" = 30'



Piedmont Municipal Power Agency

BOARD PACK

for

PMPA Board Meeting

Thursday, June 18, 2026

10:00 AM (EDT)

Held at:

PMPA Office

121 Village Drive, Greer, SC 29651

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Agenda

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6.1 a	SA no 355 DEC PMPA NITSA (11 1 26).....	22

AGENDA

PMPA BOARD MEETING



Name:	Piedmont Municipal Power Agency
Date:	Thursday, June 18, 2026
Time:	10:00 AM to 2:00 PM (EDT)
Location:	PMPA Office, 121 Village Drive, Greer, SC 29651 https://pmpa.zoom.us/j/85252653005?pwd=1JKm6GBLma1MzQYHltzNGTJvIcBS7.1
Board Members:	Andy Sevic (Chair), Blake Stone, Mayor Brian Ramey, David Dorman, David Vehaun, Eric Goodwin, Mayor Foster Senn, Jason Taylor, Jimmy Bagley, Joe Nichols, Joey Meadors, John Young, Keith Wood, Kevin Bronson, Lance Davis, Marc Regier, Mike Richard, Mike Clary, Mayor Randy Randall, Steve Bratton
Attendees:	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, 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 - 21 May 2026	6
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2.2 Approval May 21, 2026 Board Meeting Minutes

3. Acceptance of Financial Report

3.1 May 2026 Finance Report

Supporting Documents:

3.1.a	May 2026 Financial Board Mailing.pdf	11
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4. Reports

4.1 Finance

4.2 Engineering

Supporting Documents:

4.2.a	2026_05_Demand Response Report.pdf	19
4.2.b	2026_05_Energy Report.pdf	20

4.3 Catawba

Supporting Documents:

4.3.a	Catawba Report June 11 2026.pdf	21
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4.4 Management

5. Presentations

5.1 Presentation and Consideration of Debt Refinancing Opportunity

6. Action Items

6.1 Approval of Revised NITSA

For Decision

Supporting Documents:

6.1.a	SA No. 355 - DEC-PMPA NITSA (11-1-26).pdf	22
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7. Executive Session

7.1 Vote to enter into Executive Session

For Decision

7.2 Discussion of matters pertaining to contractual negotiations

7.3 Discussion of matters involving attorney/client privilege

7.4 Personnel

7.5 Vote to return to Regular Session

For Decision

8. Adjourn

8.1 Adjourn

Agenda : PMPA Board Meeting - Jun 18, 2026

Next meeting: PMPA Board Meeting - Aug 20, 2026, 10:00 AM

MINUTES (in Review)

PMPA BOARD MEETING



Name:	Piedmont Municipal Power Agency
Date:	Thursday, May 21, 2026
Time:	10:00 AM to 12:24 PM (EDT)
Location:	PMPA Office, 121 Village Drive, Greer, SC 29651
Board Members:	Andy Sevic (Chair), Blake Stone, Mayor Brian Ramey, David Dorman, David Vehaun, Eric Goodwin, Mayor Foster Senn, Jimmy Bagley, Joe Nichols, Joey Meadors, John Young, Keith Wood, Kevin Bronson, Lance Davis, Marc Regier, Mike Richard, Mike Clary, Mayor Randy Randall
Attendees:	Dennis Cameron, Gary Brunault, Joel Ledbetter, JulieAnne London, Kenny Bradley, Mike Frazier, Rion Foley, Tracy Quinn
Apologies:	Jason Taylor, Steve Bratton, Angie Hoover, Brandon Audet, Cindy Frierson, Dedra Howell, Lynn Price, Robby Townsend, Will Blanton
Guests:	Tim Baker, Scott Motsinger, Mike Jolly, Gary Brunault, Mark White, Mike Colo, and Andrea Kelley
Notes:	Virtual Attendees: Blake Stone, Kevin Bronson, Mike Jolly, Gary Brunault, Mike Colo, 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. Approval of Minutes

2.1 Confirm Minutes

PMPA Board Meeting Apr 16, 2026, the minutes were confirmed as presented.

PMPA Board Meeting May 7, 2026, the minutes were confirmed as presented.

2.2 Approval April 16 and May 7, 2026 Board Meeting Minutes



Approval April 16 and May 7, 2026 Board Meeting Minutes

A motion was made to approve the minutes of the April 16, 2026 and May 7, 2026 Board meeting.

10 Supported

0 Opposed

0 Abstained

Decision Date: May 21, 2026
Mover: John Young
Seconder: David Dorman
Outcome: Approved

3. Acceptance of Financial Report

3.1 April 2026 Finance Report



April 2026 Finance Report

10 Supported

0 Opposed

0 Abstained

Decision Date: May 21, 2026
Mover: Mayor Foster Senn
Seconder: Mayor Randy Randall
Outcome: Approved

4. Reports

4.1 Finance

Nothing to report this month.

4.2 Engineering

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

Mr. Frazier provided an update on the System Impact Studies for Rock Hill, Laurens, and Gaffney.

4.3 Catawba

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

Mr. Cameron advised the Board that he recently attended the annual Nuclear Non-Operating Owners' Group (NNOG). The group recommenced this year. The group was formed in the mid-1980s and met annually until COVID. He reviewed the speakers and topics that were discussed during the conference.

4.4 Management

Mr. Ledbetter advised the Board that he recently participated in a tour of the V. C. Summer Nuclear Station as a member of the Santee Cooper Stakeholder Advisory Group.

He reminded the Board of the APPA National Conference in June.

Mr. Ledbetter stated the annual Power Conference was originally designed to educate the members' elected officials. He stated that only 56% are registered this year, and it may be time to reevaluate whether the conference is needed.

He also provided information on current legislative items.

5. Action Items

5.1 Disposition of PMPA Transmission Assets upon termination of SPSA



Disposition of PMPA Transmission Assets upon termination of SPSA

A motion was made by Mr. Richard, seconded by Mayor Randall as follows:

- All Participants that are not signing a new supplemental power sales agreement (SPSA) with PMPA will receive payment for its positive net equity in PMPA's transmission tap lines upon termination of its existing SPSA with PMPA.

For the purposes of this Board action net equity shall mean the book value of PMPA transmission assets constructed with PMPA working capital allocatable to a Participant based on the Participant's base billing demand in effect at the time of construction of the transmission asset, less the book value of PMPA's transmission assets used by the Participant. If the difference is positive the Participant will receive a payment. If the difference is negative the Participant shall make payment.

- Payment of a Participant's positive net equity as defined above shall not be paid from funds that accrue to PMPA's Working Capital by the application of the PMPA All-Requirements rate to the billing determinants of a Participant.
- Participants that sign a new supplemental agreement with PMPA shall pay a transmission fee that recovers (a) the book value of the transmission asset used by the Participant over the remaining asset life, (b) recovers the cost of operations and maintenance of the tap line, and (c) pays a return on the book value of the asset. The details of the charge will be approved by subsequent Board action.
- Those renewing the supplemental power sales agreement (SPSA) can pay the net payment due, or a portion of the net payment due, at any time and the transmission fee will be adjusted accordingly. PMPA agrees to release from the current NITSA any Participant requesting release upon termination of Participant's existing SPSA with PMPA.

10 Supported
 0 Opposed
 0 Abstained

Decision Date: May 21, 2026
Mover: Mike Richard
Seconded: Mayor Randy Randall
Outcome: Approved

5.2 PMPA Letter of Credit for Network Transmission



PMPA Letter of Credit for Network Transmission

A motion was made by Mayor Senn with a second by Mr. Dorman to authorize either the General Manager or Finance Director of PMPA to execute a Letter of Credit (LOC) in an amount not to exceed \$17 million with Wells Fargo upon terms that are acceptable to the General Manager and Finance Director, and to authorize PMPA to open a bank account with Wells Fargo to facilitate the LOC.

10 Supported

0 Opposed

0 Abstained

Decision Date: May 21, 2026
Mover: Mayor Foster Senn
Seconder: David Dorman
Outcome: Approved

6. Executive Session

6.1 Vote to enter into Executive Session



Vote to enter into Executive Session

10 Supported

0 Opposed

0 Abstained

Decision Date: May 21, 2026
Mover: Mayor Foster Senn
Seconder: Joe Nichols
Outcome: Approved

6.2 Discussion of matters pertaining to contractual negotiations

6.3 Discussion of matters involving attorney/client privilege

6.4 Vote to return to Regular Session



Vote to return to Regular Session

10 Supported

0 Opposed

0 Abstained

Decision Date: May 21, 2026
Mover: Mayor Randy Randall
Seconder: Joe Nichols
Outcome: Approved

7. Participant Discussion

7.1 Participant Discussion

It was announced by Sen. Lindsay Graham's office that the City of Westminster has received congressionally directed spending in the Homeland Security Appropriations bill for FY 2026 an amount of \$1,314,000 for its Water Treatment Plant.

8. Adjourn

8.1 Adjourn

Next meeting: PMPA Board Meeting - Jun 18, 2026, 10:00 AM

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

Signature: _____

Date: _____

PIEDMONT MUNICIPAL POWER AGENCY
COMPARATIVE STATEMENT OF NET POSITION
AS OF MAY 31, 2026
(DOLLARS IN THOUSANDS)

	<u>LAST MONTH</u>	<u>INCREASE</u>	<u>DECREASE</u>	<u>THIS MONTH</u>
ASSETS				
CURRENT UNRESTRICTED ASSETS:				
Cash And Markable Debt Securities (W/C)	\$73,725	\$0	\$6,112	\$67,613
Revenue Fund Valuation	(1)	0	0	(1)
Participants Accounts Receivable (W/C)	16,998	736	0	17,734
Other Accounts Receivable (W/C)	117	3,570	0	3,687
Materials & Supplies	20,838	295	0	21,133
TOTAL CURRENT UNRESTRICTED ASSETS	111,677	0	1,511	110,166
CURRENT RESTRICTED ASSETS:				
Debt Service	29,105	7,226	0	36,331
Debt Service Reserve	37,847	0	0	37,847
Reserve and Contingency	2,858	1,284	0	4,142
Fuel	0	0	0	0
Fuel Fund Valuation	0	0	0	0
Decommissioning	149,238	628	0	149,866
Supplemental Power Reserve	1,600	0	0	1,600
Restricted Funds Valuation	280	0	0	280
TOTAL CURRENT ASSETS	332,604	7,627	0	340,231
CAPITAL ASSETS, NET:				
Generation	370,538	0	808	369,731
Transmission	3,928	0	11	3,916
Operational Technology	606	0	17	589
IT/General	430	0	10	420
Nuclear Fuel - In Stock And Progress	39,134	0	8,713	30,421
Nuclear Fuel - In Reactor	19,466	9,515	0	28,981
Construction In Progress	23,350	848	0	24,199
TOTAL CAPITAL ASSETS, NET	457,452	804	0	458,256
OTHER NON CURRENT ASSETS:				
Net Costs Recoverable From Future Participants Billings	162,318	0	5,101	157,217
Participant Settlement Receivable	45,400	0	0	45,400
TOTAL NON CURRENT ASSETS	665,170	0	4,297	660,873
TOTAL ASSETS	\$997,774	\$3,330	\$0	\$1,001,104
DEFERRED OUTFLOWS:				
Asset Retirement Obligation	\$35,632	\$0	\$79	\$35,553
Redemption Losses, Net	3,361	0	54	3,307
Losses On Advanced Refunding Of Debt, Net	3,445	0	72	3,374
TOTAL DEFERRED OUTFLOWS	\$42,438	\$0	\$204	\$42,234

PIEDMONT MUNICIPAL POWER AGENCY
COMPARATIVE STATEMENT OF NET POSITION
AS OF MAY 31, 2026
(DOLLARS IN THOUSANDS)

	<u>LAST MONTH</u>	<u>INCREASE</u>	<u>DECREASE</u>	<u>THIS MONTH</u>
LIABILITIES				
CURRENT LIABILITIES:				
Accounts Payable - General (WC)	\$0	\$61	\$0	\$61
Accounts Payable - Duke (WC)	1,539	0	318	1,221
Accounts Payable - Other (WC)	3,176	0	1,716	1,459
Accrued Expenses - Payroll (W/C)	0	0	0	0
Accrued Expenses - Vacation (W/C)	93	0	0	93
Accrued Expenses - Sick (W/C)	220	0	0	220
Accrued Expenses - Property Taxes (W/C)	3,334	833	0	4,167
TOTAL CURRENT LIABILITIES	8,362	0	1,141	7,221
CURRENT LIABILITIES PAYABLE FROM RESTRICTED ASSETS:				
Accrued Interest Payable	159,354	2,534	0	161,889
TOTAL CURRENT LIABILITIES	167,716	1,393	0	169,109
LONG-TERM LIABILITIES:				
Bonds - Including Current Installment	330,480	0	0	330,480
Bonds - Settlement	48,330	0	0	48,330
Bond Discounts	(25)	0	0	(24)
Bond Premium	28,338	0	535	27,803
CAB	62,800	0	0	62,800
Asset Retirement Obligation	190,647	511	0	191,158
Participant Interest Payable (W/C)	225	8	0	233
Other Postemployment Benefits	2,018	0	0	2,018
TOTAL LONG-TERM LIABILITIES	662,813	0	16	662,797
TOTAL LIABILITIES	\$830,529	\$1,377	\$0	\$831,907
DEFERRED INFLOWS:				
Postemployment Benefits	\$68	\$0	\$0	\$68
NET POSITION				
Net Investments In Capital Assets	\$42,664	\$1,214	\$0	\$43,878
Restricted For Other	1,600	0	0	1,600
Unrestricted	165,350	535	0	165,885
TOTAL NET POSITION	\$209,615	\$1,748	\$0	\$211,363
INFORMATIONAL PURPOSES:				
Working Capital	\$82,254	\$0	\$673	\$81,581

PIEDMONT MUNICIPAL POWER AGENCY
FINANCIAL SUMMARY
AS OF MAY 31, 2026

(In Millions)	MAY VARIANCES		
	\$	%	Comments
Working Capital	(\$0.09)	-16.2%	
Participant Power Sales	\$0.00	0.0%	
Surplus Sales	(\$0.01)	-2.4%	
Miscellaneous Income/Expense	\$0.07	10.6%	Lower than budgeted Duke fees
Interest Income	(\$0.09)	-9.7%	Lower than budgeted yields on the Revenue and Decommissioning funds
Catawba Project Costs	\$0.13	2.2%	
Supplemental Power Costs	\$0.56	11.9%	Lower backstand purchases (\$250k), lower Santee purchases (\$80k), favorable energy imbalance credits (\$90k), lower than budgeted Union billing credit (\$70k), Lower load management and transmission maintenance fees (\$70k)
Catawba Capital Additions	\$0.95	53.0%	Lower than budgeted expenses due to timing of expenses
PMPA Capital Additions	\$0.41	98.8%	Timing of Laurens Transmission line project
Other	(\$2.11)	-30.4%	R&C transfer timing due to Capital Additions offset (\$950K), higher than budgeted Fuel Deposits (\$800K), inventory adjustments (\$260K), Other (\$100K)

(In Millions)	YEAR-TO-DATE VARIANCES		
	\$	%	Comments
Working Capital	\$0.29	2.8%	
Participant Power Sales	\$0.80	0.9%	
Surplus Sales	\$0.58	20.9%	Higher quantity (10%) and pricing received (10%) for energy sales than budgeted
Miscellaneous Income/Expense	\$0.33	9.4%	Lower than budgeted Duke fees
Interest Income	(\$0.29)	-6.4%	Lower than budgeted yields on the Revenue and Decommissioning funds
Catawba Project Costs	\$3.72	12.4%	November & December 2025 adjustments in O&M , G&A and Insurance, coupled with Unit 2 forced outage McGuire exchange impacts from April
Supplemental Power Costs	(\$3.43)	-16.0%	Higher than budgeted backstand energy needs (51%), higher supplemental energy needs (34%), and pricing (141%) than budgeted
Catawba Capital Additions	\$1.81	15.0%	Lower than budgeted expenses due to timing of expenses
PMPA Capital Additions	\$1.85	92.6%	Timing of Laurens Transmission line project
Other	(\$5.08)	-13.0%	R&C transfer timing due to Capital Additions offset (\$1.81M) higher than budgeted Fuel Deposits (\$2.15M) and lower than budgeted McGuire Exchange sales due to Unit 2 forced outage (\$1.30M), offset by Other of \$0.18M

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

PIEDMONT MUNICIPAL POWER AGENCY

STATEMENT OF REVENUE & EXPENSE PER THE BOND RESOLUTION

AS Of MAY 31, 2026

(DOLLARS IN THOUSANDS)

	CURRENT MONTH			YEAR TO DATE			
	ACTUAL	BUDGET	OVER(UNDER)	ACTUAL	BUDGET	OVER(UNDER)	%
CATAWBA PROJECT:							
CATAWBA POWER SALES							
Participant	\$14,405	\$13,391	\$1,014	\$67,367	\$67,941	(\$574)	(0.8%)
Duke-Exchange Energy	820	1,002	(182)	3,763	5,062	(1,299)	(25.7%)
Other-Surplus	568	582	(14)	3,359	2,778	581	20.9%
TOTAL	<u>15,794</u>	<u>14,975</u>	<u>819</u>	<u>74,489</u>	<u>75,781</u>	<u>(1,292)</u>	<u>(1.7%)</u>
CATAWBA POWER COSTS							
Operations & Maintenance	1,699	1,745	(46)	7,198	8,989	(1,791)	(19.9%)
Fuel Amort (Fuel Acct Deposit)	997	1,018	(21)	5,188	5,537	(349)	(6.3%)
Purch Power-Duke-McGuire Cap	21	21	0	101	102	(1)	(0.8%)
-McGuire Energy	1,086	1,045	41	4,082	4,732	(650)	(13.7%)
Customer Acct and G&A-Duke	778	747	31	3,122	3,736	(614)	(16.4%)
Customer Acct and G&A-Agency	334	456	(122)	1,849	2,145	(296)	(13.8%)
Property Tax Equivalent	825	825	0	4,125	4,127	(2)	0.0%
Tax Other-Duke	100	112	(12)	538	560	(22)	(4.0%)
TOTAL	<u>5,840</u>	<u>5,969</u>	<u>(129)</u>	<u>26,204</u>	<u>29,928</u>	<u>(3,724)</u>	<u>(12.4%)</u>
FUNDS AVAILABLE FROM OPERATIONS	9,953	9,006	947	48,286	45,853	2,433	5.3%
INTEREST INCOME	878	972	(94)	4,172	4,459	(287)	(6.4%)
MISCELLANEOUS INCOME(EXPENSE)	(628)	(702)	74	(3,176)	(3,507)	331	(9.4%)
FUNDS AVAILABLE FOR CAPITAL NEEDS	<u>10,203</u>	<u>9,276</u>	<u>927</u>	<u>49,281</u>	<u>46,805</u>	<u>2,476</u>	<u>5.3%</u>
OTHER AVAILABLE FUNDS							
Debt Service-Principal	0	0	0	27,064	27,064	0	0.0%
-Interest	0	0	0	49,980	49,973	7	0.0%
Reserve & Contingency - Capital Additions	843	1,795	(952)	10,278	12,091	(1,813)	(15.0%)
Fuel	1,799	33	1,766	15,277	11,119	4,158	37.4%
DEPOSITS							
Debt Service-Principal	3,116	3,116	0	15,582	15,581	1	0.0%
-Interest	3,908	3,907	1	19,533	19,537	(4)	0.0%
Reserve & Contingency	2,127	2,127	0	10,635	10,635	0	0.0%
Fuel - Additional Required Deposits	802	0	802	10,089	7,943	2,146	27.0%
Decommissioning	628	664	(36)	3,172	3,258	(86)	(2.6%)
PAYMENTS							
Debt Service-Principal	0	0	0	27,064	27,064	0	0.0%
-Interest	0	0	0	49,980	49,973	7	0.0%
Capital Additions	843	1,795	(952)	10,278	12,091	(1,813)	(15.0%)
Fuel	1,799	33	1,766	15,277	11,119	4,158	37.4%
Inventory	295	40	255	65	(69)	134	(193.9%)
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	(673)	(578)	(95)	(9,794)	(10,080)	286	(2.8%)
Supplemental Working Capital	0	0	0	0	0	0	0.0%
WORKING CAP INCREASE(DECREASE)	<u>(\$673)</u>	<u>(\$578)</u>	<u>(\$95)</u>	<u>(\$9,794)</u>	<u>(\$10,080)</u>	<u>\$286</u>	<u>(2.8%)</u>

PIEDMONT MUNICIPAL POWER AGENCY
STATEMENT OF REVENUE & EXPENSE PER THE BOND RESOLUTION
AS OF MAY 31, 2026
(DOLLARS IN THOUSANDS)

	CURRENT MONTH			YEAR TO DATE			
	ACTUAL	BUDGET	OVER(UNDER)	ACTUAL	BUDGET	OVER(UNDER)	%
SUPPLEMENTAL:							
SUPPLEMENTAL POWER SALES							
Participants-Supplemental Power	3,982	4,995	(1,013)	24,195	22,818	1,377	6.0%
-Leased Facilities	26	26	0	132	131	1	0.6%
-Other	144	99	45	695	498	197	39.6%
TOTAL	4,153	5,120	(967)	25,022	23,447	1,575	6.7%
SUPPLEMENTAL POWER COSTS							
Purch Power-Supp Capacity	1,043	1,062	(19)	5,215	5,310	(95)	(1.8%)
-Supp Energy	541	1,037	(496)	6,489	2,985	3,504	117.4%
Purch Power-Participants	1,076	1,137	(61)	5,488	5,783	(295)	(5.1%)
Purch Power-Other	263	251	12	1,496	1,304	192	14.8%
Transmission	1,081	1,006	75	5,296	5,047	249	4.9%
Transmission-Agency	0	4	(4)	0	20	(20)	(100.0%)
Leased Facilities-Duke	37	36	1	184	183	1	0.7%
Meter-Agency	0	28	(28)	123	138	(15)	(10.7%)
Customer Acct and G&A-Duke	0	0	0	0	0	0	0.0%
Customer Acct and G&A-Agency	94	131	(37)	522	614	(92)	(15.1%)
Property Tax Equivalent	8	8	0	42	40	2	4.0%
TOTAL	4,143	4,700	(557)	24,855	21,424	3,431	16.0%
FUNDS AVAILABLE FROM OPERATIONS	10	420	(410)	167	2,023	(1,856)	(91.7%)
MISCELLANEOUS INCOME(EXPENSE)	198	198	0	990	990	0	0.0%
FUNDS AVAILABLE FOR CAPITAL NEEDS	207	618	(411)	1,157	3,013	(1,856)	(61.6%)
PAYMENTS							
Debt Service-Interest	202	202	0	1,009	1,010	(1)	(0.1%)
Capital Additions-Transmission	5	385	(380)	103	1,927	(1,824)	(94.7%)
-Operational Technology	0	0	0	29	40	(11)	(28.6%)
-IT/General	0	31	(31)	17	36	(19)	(53.0%)
WORKING CAP INCREASE(DECREASE)	\$0	\$0	\$0	\$0	\$0	\$0	0.0%

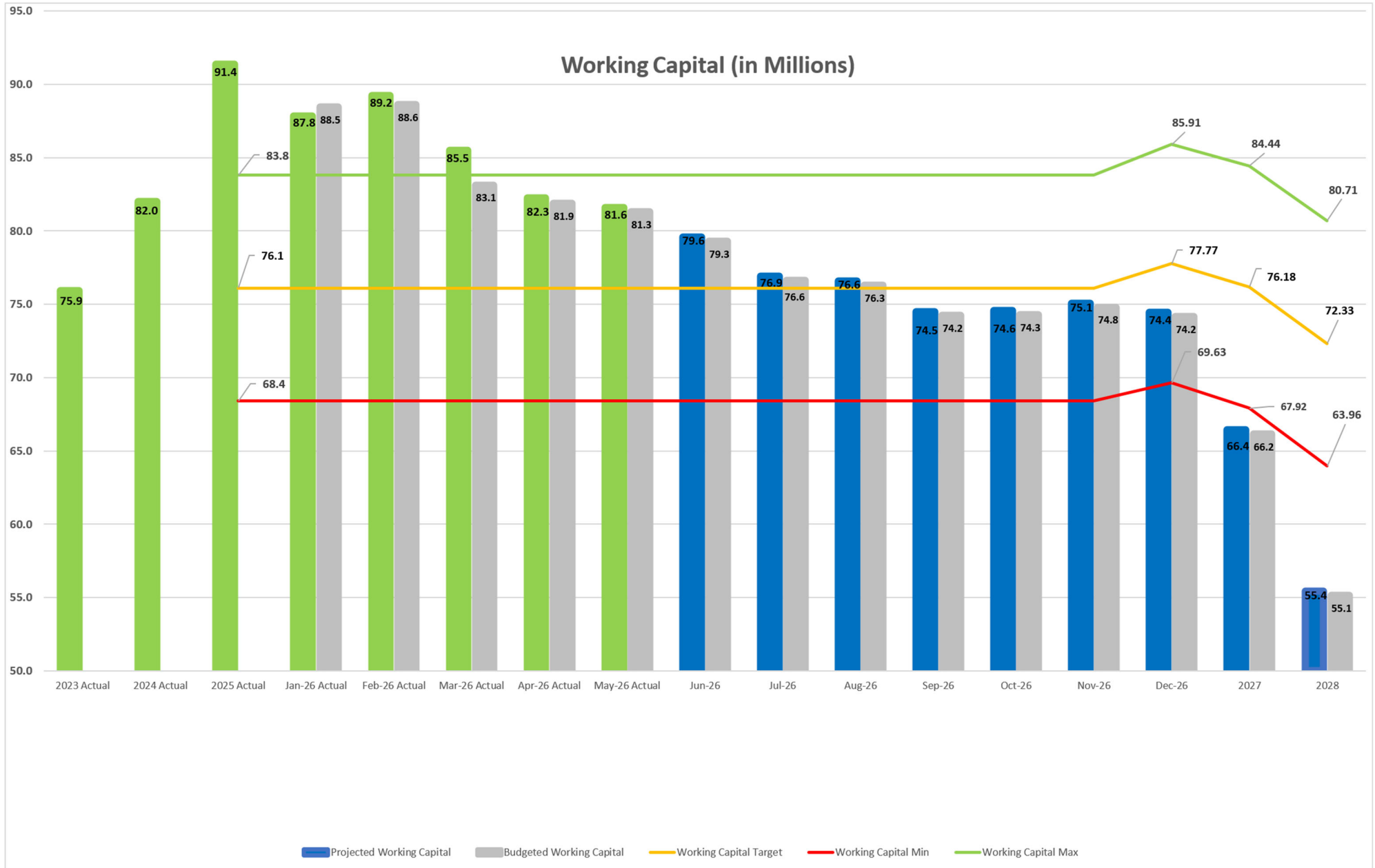
PIEDMONT MUNICIPAL POWER AGENCY STATEMENT OF G&A EXPENSE AS OF MAY 31, 2026

CURRENT MONTH				YEAR TO DATE				ANNUAL BUDGET	
ACTUAL	BUDGET	OVER(UNDER)	%	ACTUAL	BUDGET	OVER(UNDER)	%	BUDGET	%
				G&A-OFFICE EXPENSE					
\$140,127	\$148,600	(\$8,473)	(5.7)	\$687,984	\$741,400	(\$53,416)	(7.2)	\$1,930,000	35.6
10,483	10,800	(317)	(2.9)	57,136	59,400	(2,264)	(3.8)	119,000	48.0
20,400	20,200	200	1.0	100,677	100,900	(223)	(0.2)	242,000	41.6
13,257	13,100	157	1.2	72,880	72,100	780	1.1	177,000	41.2
33,425	29,100	4,325	14.9	115,923	115,200	723	0.6	175,700	66.0
1,530	2,100	(570)	(27.1)	9,088	10,500	(1,412)	(13.4)	25,000	36.4
1,251	1,600	(349)	(21.8)	6,059	8,000	(1,941)	(24.3)	18,600	32.6
1,573	1,200	373	31.1	4,513	6,000	(1,487)	(24.8)	14,200	31.8
1,032	3,900	(2,868)	(73.5)	11,210	13,300	(2,090)	(15.7)	56,900	19.7
2,509	2,800	(291)	(10.4)	10,456	22,500	(12,044)	(53.5)	48,700	21.5
0	0	0	0.0	30,936	28,000	2,936	10.5	128,000	24.2
13,135	21,000	(7,865)	(37.5)	46,029	64,800	(18,771)	(29.0)	159,000	28.9
2,731	300	2,431	810.3	16,889	1,300	15,589	1,199.2	223,090	7.6
373	20,100	(19,727)	(98.1)	8,480	29,500	(21,020)	(71.3)	96,500	8.8
65,496	104,000	(38,504)	(37.0)	135,759	180,700	(44,941)	(24.9)	300,500	45.2
499	5,400	(4,901)	(90.8)	31,467	38,900	(7,433)	(19.1)	41,400	76.0
4,817	1,000	3,817	381.7	67,213	72,400	(5,187)	(7.2)	94,700	71.0
8,940	9,200	(260)	(2.8)	55,189	46,000	9,189	20.0	111,000	49.7
321,578	394,400	(72,822)	(18.5)	1,467,888	1,610,900	(143,012)	(8.9)	3,961,290	37.1
				G&A-OUTSIDE SERVICES					
60,921	68,100	(7,179)	(10.5)	346,856	340,300	6,556	1.9	817,000	42.5
22,717	28,300	(5,583)	(19.7)	78,211	156,600	(78,389)	(50.1)	355,000	22.0
5,438	31,800	(26,362)	(82.9)	131,851	159,600	(27,749)	(17.4)	374,200	35.2
0	0	0	0.0	0	0	0	0.0	0	0.0
450	2,400	(1,950)	(81.3)	6,725	12,000	(5,275)	(44.0)	28,500	23.6
89,526	130,600	(41,074)	(31.5)	563,643	668,500	(104,857)	(15.7)	1,574,700	35.8
				G&A-BOARD REIMBURSEMENTS					
4,502	10,300	(5,798)	(56.3)	193,014	197,700	(4,686)	(2.4)	210,000	91.9
9,966	11,700	(1,734)	(14.8)	50,213	83,500	(33,287)	(39.9)	210,000	23.9
2,000	40,000	(38,000)	(95.0)	96,000	200,000	(104,000)	(52.0)	280,000	34.3
16,468	62,000	(45,532)	(73.4)	339,227	481,200	(141,973)	(29.5)	700,000	48.5
\$427,572	\$587,000	(\$159,428)	(27.2)	\$2,370,758	\$2,760,600	(\$389,842)	(14.1)	\$6,235,990	38.0
				TRANSMISSION/ENERGY EFFICIENCY					
\$0	\$4,000	(\$4,000)	(100.0)	\$0	\$20,000	(\$20,000)	(100.0)	\$50,000	0.0
0	28,000	(28,000)	(100.0)	123,181	138,000	(14,819)	(10.7)	177,000	69.6
\$0	\$32,000	(\$32,000)	(100.0)	\$123,181	\$158,000	(\$34,819)	(22.0)	\$227,000	54.3

PIEDMONT MUNICIPAL POWER AGENCY

AS OF MAY 31, 2026

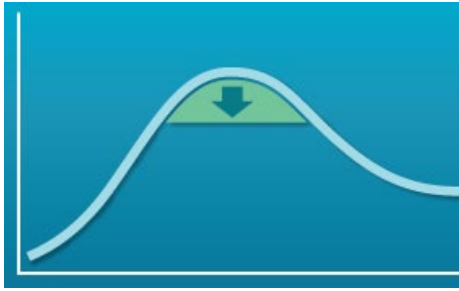
After this month's operations, PMPA had \$81.6 million in working capital, which was \$0.3 million more than the YTD budget.



Note: Assumes no rate increases from 2026 to 2028.

PMPA
CASH AND MARKETABLE DEBT SECURITIES ROLLFORWARD
FROM 5/1/2026 TO 5/31/2026

	Operating Account	Revenue Fund	Total
Beginning Balance	234,931.31	73,490,687.29	73,725,618.60
<u>Cash Receipts/Payments</u>			
Cash Receipts			
From Participants	6,173.08	16,983,676.77	
From Other	3,286.60	(3,345,555.00)	
Vendor payments	(500,165.67)	-	
Vendor payments - Capital - Transmission	(5,497.00)		
Vendor payments - Capital - Operational Technology	-		
Vendor payments - Capital - IT/General	-		
Duke Operating Statement		(5,771,855.31)	
Duke Uprate		(368,372.29)	
Duke Instantaneous		9,414.10	
Duke Transmission		(1,388,070.93)	
Duke Interconnect		(151,246.52)	
Santee Cooper		(1,182,953.15)	
TEA		(1,966,538.50)	
York Property Taxes		-	
Payroll	(161,270.68)	-	
US Bank Credit Card Payment	(11,861.74)	-	
<u>Account Transfers</u>			
Operating Account Funding	1,000,000.00	(1,000,000.00)	
R&C Account Funding - 1/12 of Annual Capital Budget		(2,126,916.67)	
Revenue Account Funding - From R&C For Capital Purchases		842,832.18	
Fuel Account Funding - Fuel Amortization		(997,211.94)	
Fuel Account Funding - Additional Required Deposits		(801,893.61)	
Revenue Account Funding - From Fuel For Purchases		1,799,105.55	
Debt Service Principal	-	(3,116,427.42)	
Debt Service Interest	-	(4,109,350.34)	
DCOM Funding		(172,836.00)	
Interest/Investment Activity	(186.75)	422,005.43	
Ending Balance	565,409.15	67,048,493.64	67,613,902.79



PMPA Demand Response System Report

To: Board of Directors and Alternates
 From: Mike Frazier *MTF*
 Date: June 10, 2026

PMPA did not call for any Demand Response events during May.

PMPA Monthly Peak¹: 464.0 MW @ Hour Ending 5:00 p.m. on May 20th

- Does NOT coincide with the Duke Energy Transmission Peak on May 20th @ Hour Ending 6:00 p.m.
- Monthly Maximum GSP Airport Temperature – 90° F on May 20th, 21th

PMPA Total Participant Load²: 505.0 MW @ Hour Ending 5:00 p.m. on May 20th

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

In June, PMPA Ratchet Quantity: 518.5 MW – based on Jul. 28, 2025 @ HE 4:00 p.m.

Temperatures ventured as high as ninety degrees F in May, however, the overall monthly average temperature was somewhat below average. PMPA set its highest peak of the month on the first ninety degree day. Weather predictions call for continuing development of an El Niño for this summer, which could lessen hurricane development and cause higher temperatures in South Carolina.

All loads are reflected at the transmission level, which includes 1.96% losses as of Jun. 1, 2025. Beginning Jun. 1, 2026, the Duke transmission loss factor will change to 2.10%.

¹ 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.

² 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>
May 2026	146	91
Normal	160	
May 2025	133	83

ENERGY REPORT ^{*}

Piedmont Municipal Power Agency

MAY, 2026

The Energy Authority (Surplus Energy Sold and Gross Revenue)

4,307	MWh	86,460	\$	20.07	\$ / MWh
23,295	MWh - YTD	527,814	\$ - YTD	22.66	\$ / MWh - YTD

Duke Energy (Surplus Energy Sold and Gross Revenue)

8,840	MWh	236,237	\$	26.72	\$ / MWh
35,435	MWh-YTD	1,171,610	\$-YTD	33.06	\$ / MWh - YTD

Santee Cooper (Surplus Energy Sold and Gross Revenue)

8,049	MWh	265,512	\$	32.99	\$ / MWh
37,803	MWh-YTD	1,496,614	\$-YTD	39.59	\$ / MWh - YTD

Total Surplus Sales Revenue

588,210	\$	33.11	\$/ MWh-YTD
3,196,038	\$ - YTD	96,533.00	MWh-YTD

Generation Imbalance Charge

(102,154)	\$
78,535	\$ - YTD

Deviation Band 1 - +/- 1.5%

Deviation Band 2 - Between +/-1.5% & 7.5%

Deviation Band 3 - Greater than +/- 7.5%

(\$14,294)

(\$35,551)

(\$52,309)

Energy Imbalance Charge

31,896	\$
173,019	\$ - YTD

Deviation Band 1 - +/- 1.5%

Deviation Band 2 - Between +/-1.5% & 7.5%

Deviation Band 3 - Greater than +/- 7.5%

\$1,116

\$6,474

\$24,306

Supplemental Energy Purchased

Santee Cooper	TEA Backstand ^{&}	Total	
10,546	4,776	15,322	MWh
33,667	54,822	88,489	MWh - YTD
445,489	261,213	706,702	\$
3,855,939	2,544,891	6,400,829	\$ - YTD
42.24	54.69	46.12	\$ / MWh
114.53	46.42	72.33	\$ / MWh - YTD

^{*} All MWh are measured at the bus bar (generation level)

[&] Includes energy and transmission costs

Catawba and McGuire Report – June 11, 2026

Since the May 21st Board meeting, Catawba Unit 1, Catawba Unit 2, McGuire Unit 1, and McGuire Unit 2 have operated continuously without any concerns.

<u>May 2026</u>	<u>Capacity Factor</u>	<u>Generation (MWhs)</u>	<u>PMPA's Entitlement (MWhs)</u>
Catawba 1	55.04%	475,018	29,688
Catawba 2	100.90 %	863,318	53,957
McGuire 1	100.93%	869,571	52,739
McGuire 2	101.43%	873,875	53,000

Catawba Unit 1 began a refueling outage on April 18 with a budgeted allocation of 28 days. The unit returned service on May 13 at 7:50 PM completing a 25.7-day outage. Catawba Unit 1 has operated continuously since the outage with no major concerns.

2026 Planned Refueling Outages

<u>Unit</u>	<u>Outage Start Date</u>	<u>Budgeted Duration</u>
McGuire 1	September 5, 2026	28 Days

Nuclear Regulatory Commission

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

OATT SERVICE AGREEMENT NO. 355

SERVICE AGREEMENT

FOR

NETWORK INTEGRATION TRANSMISSION SERVICE

BETWEEN

DUKE ENERGY CAROLINAS, LLC

AND

PIEDMONT MUNICIPAL POWER AGENCY

SERVICE AGREEMENT FOR NETWORK INTEGRATION TRANSMISSION SERVICE

1.0 PARTIES

This Service Agreement, dated as of November 1, 2026 is entered into, by and between **Duke Energy Carolinas, LLC** (“Transmission Provider”) and **Piedmont Municipal Power Agency** (“Transmission Customer”) sometimes hereinafter referred to individually as “Party” and collectively as “Parties”.

2.0 COMPLETED APPLICATION

The Transmission Customer has been determined to have a Completed Application for Network Integration Transmission Service under Transmission Provider’s Open Access Transmission Tariff (the “Tariff”).

If the corporate identity or name of Transmission Customer is to change during the term of this Service Agreement, Transmission Customer shall notify Transmission Provider as soon as possible after learning of said projected change. In such event Transmission Provider may in its reasonable discretion require a new Application for Network Integration Transmission Service and/or the execution of an appropriate amendment of this Service Agreement.

3.0 TERM

Unless the Federal Energy Regulatory Commission (“FERC” or the “Commission”) orders a different date for commencement of service, service under this Service Agreement shall commence on November 1, 2026 and continue to April 1, 2042.

4.0 EFFECT OF ISO/RTO PARTICIPATION

This Service Agreement and the Attachments thereto (collectively, the “Service Agreement” or “Agreement”), have been developed by the Parties in the context of transmission service provided pursuant to the Tariff and the Commission’s open access requirements under Order No. 888 and Order No. 890. Were the Transmission Provider to join a Regional Transmission Organization (“RTO”) (which term includes an independent system operator), the Transmission Provider is permitted to assign this service agreement to the RTO, in which case transmission service would be provided to the Transmission Customer pursuant to the rates, terms and conditions of the open access transmission tariff of the RTO (“RTO OATT”), and other terms, conditions, rules and/or protocols of the RTO. The Parties further agree that in the event of a material inconsistency or conflict between the RTO OATT or such other terms, conditions, rules and/or protocols of the RTO and the Service Agreement, that the Service Agreement may require amendment to account for such changed circumstance. In such event, at the request of either Party or the RTO, the Transmission Customer and the RTO (and the Transmission Provider, if appropriate)

shall enter into good faith negotiations to amend the Service Agreement in a manner such that the transmission service is provided in accordance with the RTO OATT and such other terms, conditions, rules and/or protocols. If the Transmission Customer and the RTO (and the Transmission Provider if appropriate) cannot agree on the necessary revisions the Transmission Customer may request that the RTO (and the Transmission Provider, if appropriate) file unexecuted amended Service Agreement with the Commission pursuant to Section 205 of the Federal Power Act such that the transmission service thereunder comports with the RTO OATT and such other terms, conditions rules and/or protocols of the RTO and the Transmission Provider shall support the Transmission Customer's right to request such filing. By agreeing to the procedure set forth above, neither Party waives any rights it might otherwise have with respect to the Service Agreement under the Federal Power Act.

5.0 NATURE OF SERVICE TO BE FURNISHED

The Transmission Provider agrees to provide, and the Transmission Customer agrees to take and pay, for Network Integration Transmission Service in accordance with the provisions of Part III of the Tariff and this Service Agreement as they may be amended from time to time. Neither Party shall be deemed, by virtue of having entered into this Service Agreement, to have agreed to diminish or enhance the rights of either Party with regard to the Commission's comparability policies, provided that the foregoing clause shall be construed in a manner most consistent with each Party performing its obligations hereunder.

6.0 NOTICES

Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Duke Energy Carolinas, LLC
 9550 Research Drive
 Charlotte, NC 28262
 Attn: Scott Lewter
 Lead System Operations Analyst
 Phone: (980) 701-8115
 E-Mail Address: Scott.Lewter@duke-energy.com

Transmission Customer:

Piedmont Municipal Power Agency
 121 Village Drive
 Greer, SC 29651
 Attn: Mike Frazier
 Director of Engineering and Power Supply
 Phone: 864 848-5409
 Fax: 864 879-2122

E-Mail: mfrazier@pmpa.com

7.0 INCORPORATION OF OTHER DOCUMENTS

The Tariff, Attachment A hereto (Specifications for Network Integration Transmission Service), Attachment B hereto (Delivery Points), Attachment C hereto (Distribution Rates), Attachment D hereto (Power Factor Penalty), Attachment E hereto (Network Operating Agreement), and Attachment F hereto (Other Charges/Credits) are incorporated herein and made a part hereof.

To the extent that any provisions in the Tariff or this Service Agreement are ambiguous or inconsistent, any such ambiguity or inconsistency will be resolved in the following priority: the Tariff, the Service Agreement (including Attachments).

8.0 BILLINGS AND BILLING ADJUSTMENTS

- 8.1 The Transmission Provider will have the right to adjust or revise any bill rendered under the Tariff no later than eighteen (18) months after the date the bill was rendered. Any billing adjustment will be in writing and will state the specific basis for the adjustment. An Adjusted Bill will constitute a new bill in regard to the adjusted components for all purposes of the Tariff and this Service Agreement.
- 8.2 The Transmission Customer may, in good faith, challenge the correctness of any bill and any adjusted or revised bills. The Transmission Customer's challenge of any bill rendered under the Tariff may include the appropriateness of all charges thereunder. Unless otherwise agreed in writing by the Parties, the Transmission Customer's challenge must be presented no later than eighteen (18) months following the date such bill is received. Any billing challenge will be in writing and will state the specific basis for the challenge. Billing challenges are limited in scope to the correctness of any bill and appropriateness of any charge. The Transmission Provider shall respond in writing to any such billing challenge within ninety (90) days. Billing challenges shall be treated as disputes pursuant to Section 7.3 of the Tariff.
- 8.3 Refunds or additional charges that are a result of an adjustment, revision, or billing challenge will include interest calculated at the rate set forth in 18 C.F.R. § 35.19a (a)(2)(iii).

9.0 AUDITS

- 9.1 In addition to the bill challenge rights set forth in Section 8.2, the Transmission Customer shall also have audit rights as set forth in this Section 9.0. The Transmission Customer shall conduct any such audit within eighteen (18) months from the date of the rendering of any bill under the Tariff. The Transmission Provider and the Transmission Customer will each have the right, upon reasonable notice, to inspect or audit each other's accounts and records supporting the bills for service under the Tariff during such calendar year. Such

audit will be performed to the extent necessary to verify the correctness of any bill and the appropriateness of all charges thereunder. The audited Party shall provide or cause to be provided all information that the auditing Party may reasonably request to substantiate all billings, adjustments or revisions to billings for service under the Tariff. Any such audit will be conducted, upon reasonable written notice, during normal business hours at the offices where such accounts and records are maintained or at a location mutually agreeable to the Parties. The audited Party shall provide to the auditing Party reasonable office accommodations to conduct the audit. Those qualified personnel identified upon reasonable written notice by the auditing Party will be permitted to conduct audits. The audited Party will be entitled to review the audit report and any supporting materials at the conclusion of the audit and prior to finalization. The accounts and records for any calendar year shall not be subject to more than one (1) audit by a Party.

- 9.2 Notwithstanding the above, if the Transmission Provider renders a billing adjustment or revision and the audit for the affected calendar year has been conducted, then the Transmission Customer may conduct an audit of the billing adjustment or revision within ninety (90) days after the adjustment is rendered and challenge such adjustment no later than one hundred and fifty (150) days after the adjustment is rendered.
- 9.3 With the exception of quantifiable changes in the amounts of the billings, the audit report, supporting materials and all other audit results of all such audits shall be kept confidential by the Parties and shall not be released to any other party without the express written consent of the other Party.

10.0 DELIVERY POINTS

The Transmission Customer Delivery Points shall be the points of connection between the Transmission Provider's facilities and the facilities of the Transmission Customer or its member systems.

11.0 ADJUSTMENT FOR LOSSES

To the extent any Delivery Point is at a voltage level less than 44 kV or the metering point(s) is (are) remote from the Delivery Point, the load associated with such Delivery Point used for the calculation of the Network Integration Transmission Service charge shall be adjusted for the losses associated with: (i) the Transmission Provider's applicable distribution facilities; and/or (ii) the Transmission Customer's distribution and transmission facilities, as applicable. Such loss compensation factors shall be as mutually agreed upon by the Parties. To the extent the Parties cannot

agree on any such factors, the Dispute Resolution Procedures in Section 12 of the Tariff may be invoked to resolve the disagreement.

12.0 NO WAIVERS

Failure of a Party to enforce any provision of this Service Agreement will not be construed as a waiver of such provision, and will not affect the validity of the Service Agreement or the right of either Party subsequently to enforce any provision of the Service Agreement. Any waiver at any time by either Party of its rights with respect to the other Party, or with respect to any matter arising in connection with this Service Agreement, will not be considered a waiver with respect to any subsequent matter. Failure of a Party to resort to any legal remedy or to exercise any one or more alternative remedies will not affect such Party's right subsequently to resort to any one or more of such rights or remedies on account of any such grounds then existing, or which may subsequently occur.

13.0 ACCEPTANCE BY FERC

The Parties recognize that this Service Agreement must be filed with the FERC and is subject to the jurisdiction of that Commission. Transmission Provider shall have the right to make a unilateral filing with the Commission to modify this Service Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder, and Transmission Customer shall have the right to make a unilateral filing with the Commission to modify this Service Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Service Agreement shall limit the rights of the Parties or of the Commission under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

DUKE ENERGY CAROLINAS, LLC

Signature: _____

By: Ben I. Harrison Jr. VP, Grid Planning _____
Name Title Date

Transmission Customer:

PIEDMONT MUNICIPAL POWER AGENCY

Signature: _____

By: Joel D. Ledbetter General Manager _____
Name Title Date

Attachment A
Specifications For
Network Integration Transmission Service

1.0 Term of Network Service:

As specified in Section 3.0 of the Service Agreement for Network Integration Transmission Service.

2.0 Description of Capacity and/or Energy to be Transmitted by Transmission Provider Across the Transmission Provider's Transmission System (including electric Control Area in which the transaction originates):

Firm capacity and energy delivered to the Transmission Provider's Transmission System in the amount of: (i) the sum of hourly metered load(s) at the metering location, compensated, where applicable, for losses on (a) the Transmission Customer's facilities to the extent the metering is remote from the Delivery Point and (b) the Transmission Provider's distribution facilities to the extent such Delivery Point is served from such facilities; plus (ii) real power losses on the Transmission Provider's Transmission System as set forth in Section 28.5 of the Tariff. The listing of the Transmission Customer's Delivery Points, as may be amended from time to time, is set forth in Attachment B to the Service Agreement. Detailed information about each of the Transmission Customer's Delivery Points shall be set forth in Delivery Point Data Sheets, executed by the Parties, substantially in the form set forth in Attachment B to the Service Agreement.

3.0 Network Resources¹

3.1 Network Resources - Owned Generation:

- a) Gaffney diesel generator (6,000 kW)

Control Area in which resource is located: Transmission Provider's Control Area

Designated Interface: none

- b) Easley diesel generator (6,200 kW)

Control Area in which resource is located: Transmission Provider's Control Area

Designated Interface: none

¹ Changes or additions to Network Resources to serve Transmission Customer load growth shall be treated as a "Designation of New Network Resources" pursuant to Section 30.2 of the Transmission Provider's Tariff.

- c) Ownership entitlements to certain Catawba Nuclear Station units (277,140 kW) pursuant to the Catawba Nuclear Station Joint Ownership Support Agreement dated June 7, 2005 and the McGuire Reliability Exchange Agreement dated June 7, 2005, together (“the 2005 Catawba Agreements”).

Control Area in which resource is located: Transmission Provider’s Control Area

Designated Interface: none

3.2 Network Resources – Contracts:

- a) SEPA Allocation (69,171 kW)

Control Area in which resource is located: SEPA Thurmond generator Control Area in SETH; SEPA Hartwell generator Control Area is SEHA

Designated Interface: SETH/SEHA/Duke

- b) Power Sales Agreement with South Carolina Public Service Authority

Control Area in which resource is located: SC (Santee Cooper)

Designated Interface: SC/Duke

“Designated Interfaces” shall mean the interface(s) between an adjacent Control Area and the Transmission Provider’s Control Area that serves as an entry point for energy from resources utilized by Transmission Customer pursuant to the designated Network Resource that are not located in the Transmission Provider’s Control Area into the Transmission Provider’s Control Area for the purpose of serving the Transmission Customer’s Network Load. Such designation shall not prevent the Transmission Customer from exercising all rights conferred by Section 30.8 of the Tariff.

4.0 Network Load

The Network Load is the demand and energy requirement for the member systems of Transmission Customer at the Delivery Points connected to the Transmission Provider’s transmission and distribution system, as set forth in Attachment B, as may be amended from time to time.

- 4.1 Transmission Customer’s load growth shall not be treated as ‘New Network Load’ pursuant to Section 31.2 of the Transmission Provider’s Tariff. Transmission Customer estimated load growth shall be reflected in the annual updates of forecasted Network Load provided pursuant to Section 31.6 of the Transmission Provider’s Tariff.

- 4.2 For purposes of calculating the Transmission Customer's load ratio share of the transmission system revenue requirement, load served by generating resources that utilize the transmission or distribution facilities of a Transmission Customer Participant to reach load ("behind-the-meter generation") shall be included in the Transmission Customer's Network Load to the extent permitted by FERC policy, provided, however, that if FERC's policy with respect to the treatment of load served by 'behind-the-meter generation' is modified, the treatment accorded Transmission Customer load served by such generation shall be conformed to FERC's modified treatment.
- 4.3 For purposes of calculating the Transmission Customer's load ratio share of the transmission system revenue requirement, Network Load shall not include load served by generating resources located "behind the second meter" that is unknown to the Transmission Customer (*i.e.*, generation that does not utilize the transmission or distribution system of a wholesale transmission customer to reach load or does not operate in synchronization with the Transmission Provider's transmission system), provided, however, that the calculation of Transmission Customer's load ratio share will be revised to include such load if: (i) FERC rules in a contested proceeding that load served by generation located behind the second meter must be included in a Transmission Customer's Load Ratio Share (and such ruling has been upheld on appeal, if any); and (ii) Transmission Provider includes all such load on its own system as part of its system load in the denominator of the Load Ratio Share calculation.
- 4.4 Transmission Customer notified Transmission Provider on January 3, 2024 with a network integration transmission service request to designate 300 MW of New Network Load with a requested in service date of September 30, 2027, per Section 31 of Transmission Provider's OATT. Transmission Customer has requested a new Delivery Point to serve such New Network Load. Transmission Provider performed a System Impact Study per Section 32 of Transmission Provider's OATT and determined a Counteroffer of 100 MW could be offered to serve Transmission Customer's requested transmission service with no network upgrades required to accommodate such service. The Counteroffer of 100 MW will be served from the new Delivery Point named Rock Hill Delivery 13.
- 4.5 Transmission Customer has requested an additional 50 MW of new Network Load to be served at new Delivery Point No. 14 (Rock Hill) by September 30, 2028 and has provided the projection of such new Network Load to be served over the Term of this Service Agreement as set forth below, therefore Transmission Customer will not: (a) connect any MW value of the new Network Load at such delivery point prior to September 30, 2028 (unless all Network Upgrades necessary to accommodate such new Network Load are completed prior to such date and the parties mutually agree to the MW value of new Network Load that can be connected prior to such date); (b) seek to

increase the MW value associated with such new Network Load; or (c) seek to decrease the MW value associated with such new Network Load.

Year	Projection of New Network Load to be Served Behind Delivery Point 14
2026	0 MW
2027	0 MW
2028	8 MW (beginning September 30, 2028)
2029	13 MW
2030	18 MW
2031	23 MW
2032	28 MW
2033	33 MW
2034	38 MW
2035	43 MW
2036	48 MW
2037	50 MW
2038	50 MW
2039	50 MW
2040	50 MW
2041	50 MW

- a. System Impact Studies and Facilities Studies Conducted by Transmission Provider.** Transmission Provider conducted a system impact study pursuant to Sections 32.1-3 of the Joint OATT and a facilities study pursuant to Section 32.4 of the Joint OATT which is required per such section of the Joint OATT to include “a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of

the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service.”

The Facilities Study report dated March 20, 2026 contained each of the required 3 elements as set forth below.

Good Faith Estimate of Cost of Direct Assignment Facilities: there were no direct assignment facilities identified in the study to be charged to the Transmission Customer.

Good Faith Estimate of Cost of Any Required Network Upgrades: the study report contained Transmission Provider’s good faith estimate of the following transmission Network Upgrades are needed to serve this new network load: (1) Install new remote controlled Gang Operated Air-break Switch on existing Transmission Customer Delivery Tap line at structure number 24.5.

Transmission Provider provided a good faith estimate of the cost of such updates as approximately \$3.35 million which is comprised of the following components: (1) costs to engineer and design the removal of existing structure and the installation of new structure with Gang Operated Air-break Switch at structure 24.5, (2) material costs to source and procure all necessary equipment based on historical pricing of procuring similar equipment in the past, estimates of quantities of equipment needed in this case, and quotes from vendors on such material costs, (3) construction costs to construct and install the Network Upgrades which includes direct charges for subcontracted labor to do so based upon scope of work for the Network Upgrades and existing labor rates, (4) indirect charges to produce a fully burden cost estimate including material loading and allocation values, overhead costs, administrative expenses, and escalator calculations to account for any cost increases based on standard methodologies employed by Transmission Provider in creating good faith cost estimates, and (5) a contingency reserve amount to cover unforeseen expenditures established as a percentage of overall direct and indirect costs (20%) which is aligned with the standard project management governance requirements employed by Transmission Provider in creating good faith cost estimates.

Good Faith Estimate of Time Required to Complete Such Construction and Initiate the Requested Service: the study report contained Transmission Provider’s good faith estimate of 30 months to complete construction of Network Upgrades.

- b. **Security.** Per Section 32.4 of Transmission Provider’s Joint OATT and upon execution of this NITSA, Transmission Customer shall provide the Transmission Provider with security (a letter of credit or cash)

“equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code.” Transmission Customer shall comply at all times relevant under this Agreement with the “Duke Energy Credit Risk Management Policy to Implement Security Required Pursuant to Section 32.4 of the Joint OATT” which is posted on Transmission Provider’s OASIS website.

c. Billing and Payment During Construction of Network Upgrades.

Transmission Provider will bill Transmission Customer monthly with actual project spends. Transmission Customer is expected to pay Transmission Provider within 30 days of bill receipt. The Transmission Customer is obligated to pay Transmission Provider’s actual costs while the project is under construction. After the project in-service or used and useful date, Transmission Provider will pay Transmission Customer a lump sum reimbursement equal to the project’s actual costs plus interest. Interest shall be calculated according to the FERC interest rate.

Per Section 31.5 (Changes in Service Requests) of the Joint OATT, “[u]nder no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g., the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement.”

In the case of a cancellation or delay of this new Network Load, (1) costs already incurred by Transmission Provider in furtherance of the new facilities and Network Upgrades and (2) costs that Transmission Provider incurs in returning the Transmission System to a safe and reliable condition (if any) will be charged to the Transmission Customer.

Payment During Dispute. In the event of a billing dispute among the Parties, Transmission Provider shall continue to construct the Network Upgrade(s) under this Agreement as long as Transmission Customer: (1) continues to make all payments not in dispute; and (2) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Transmission Customer fails to meet these two requirements, then Transmission Provider may provide notice to Transmission Customer of a Default pursuant to Breach, Cure and Default section. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to another Party shall pay the amount due with interest calculated in accordance with the methodology set forth in 18 C.F.R. § 35.19a(a)(2)(iii).

d. Cost Recovery of Network Upgrades Once Placed In Service. Once

the Network Upgrades have been fully constructed, Transmission Provider shall include its actual costs to construct the Network Upgrades (if such costs differ from its estimated costs) and its reimbursement expense to Transmission Customer as described above into transmission rates after the Network Upgrades are placed in service. Transmission Provider shall release the security provided by Transmission Customer within 90 days following the in service date of the Network Upgrades.

- e. **Breach, Cure and Default.** A breach of this Service Agreement shall include (a) the failure to provide and maintain security when due, or (b) the failure to pay any amount when due. Upon a breach, the non-breaching Party shall give written notice of such breach to the breaching Party. The breaching Party shall have thirty (30) calendar days from receipt of the notice to cure the breach.

If a breach is not cured within the 30-day period, (1) the breaching Party is automatically in default of this Service Agreement and (2) the non-breaching Party shall be relieved of any further applicable obligation and is entitled to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity.

Transmission Provider may draw on security if an event of default has occurred or is ongoing and any applicable cure period has passed, or security in the form of a letter of credit is within 30 days of expiration and Transmission Customer has not provided Transmission Provider with an amendment extending the expiration of the letter of credit. Transmission Provider reserves the right to not reduce security if an event of default has occurred or is ongoing, or if Transmission Customer has not made all required payments.

5.0 Designation of Party Subject to Reciprocal Service Obligation:

The Transmission Customer

6.0 Service Under this Agreement may be Subject to Some Combination of the Charges Detailed Below. All such applicable charges shall be billed in accordance with the terms and conditions of the Tariff.

6.1 Transmission Charge:

As per the Tariff, Part III Section 34.

6.2 Facilities Study Charge:

Not Applicable.

6.3 Direct Assignment Facilities Charge:

As per the Tariff and Commission's approval of directly assignable charges

6.4 Ancillary Services Charge:

Schedule 1, Scheduling, System Control and Dispatch Service: The charges for **Scheduling, System Control and Dispatch Service** are as provided per the Tariff, Schedule 1.

Schedule 2, Reactive Supply and Voltage Control from Generation Sources Service: The charges for **Reactive Supply and Voltage Control from Generation Sources Service** are provided per the Tariff, Schedule 2. The Transmission Customer may satisfy all or part of its obligation through self-provision or purchases from generating facilities under the control of the Control Area operator.

The Transmission Customer will receive compensation in the amount of

0.71 x (Transmission Customer's Retained Capacity (As defined in the McGuire Reliability Exchange Agreement dated June 7, 2005) / Rolling 12-month average Transmission System Peak Demand)) x (Schedule 2 Annual Revenue Requirement / 12)

Schedule 3, Regulation and Frequency Response Service: The Transmission Customer may satisfy all or part of its obligation through self-provision or purchases from generating facilities under the control of the Control Area operator.

*For any portion of its load in excess of its ownership entitlement as specified in Section 3.0 of these Specifications, Transmission Customer must either purchase **Regulation and Frequency Response Service** from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligations. Initially, the Transmission Customer has elected to self-supply this service up to the amount of its ownership entitlement used for Network Load. For Network Load in excess of its ownership entitlement, Transmission Customer has made alternative comparable arrangements for the supply of this service by South Carolina Public Service Authority. To the extent the service is provided by the Transmission Provider, the charges for this service are as provided per the Tariff, Schedule 3. During Successful Operation of the dynamic scheduling arrangements (as defined in Section 7.0 of Attachment E), the Transmission Provider will not charge Transmission Customer for Regulation and Frequency Response Service under Schedule 3. If such Successful Operation does not occur for a cumulative period greater than five (5) hours in any calendar month, Transmission Customer will be deemed to have purchased Schedule 3 service from the Transmission Provider at a rate equal to the applicable Point-to-Point rates sets forth in the Tariff Schedule 3, for Network*

Load above the level of its ownership entitlement. The minimum purchase duration is equal to one week. The charge shall be the minimum charge that can be derived given the Network Load of Transmission Customer above the level of its ownership entitlement and the applicable rates. For example, Transmission Customer will purchase monthly service when that is less costly than purchasing weekly service.

Schedule 4, Energy Imbalance Service: Transmission Customer must either purchase **Energy Imbalance Service** from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligations.

Initially Transmission Customer has elected to purchase Energy Imbalance Service from the Transmission Provider.

Schedule 5, Operating Reserve - Spinning Reserve Service: The Transmission Customer must either purchase Operating Reserve - Spinning Reserve Service from the Transmission Provider or make alternative comparable arrangements to satisfy its Operating Reserve - Spinning Reserve Service obligations. The charges for this service are as provided per the Tariff, Schedule 5.

The Transmission Provider is providing reserves to Transmission Customer pursuant to Tariff Schedule 5 for 277 MWs of its ownership entitlement. As of the date of this agreement, charges for this service shall be calculated based upon 72 MWs which is the first contingency the Transmission Customer and the Transmission Provider include in their planning models. In addition, the Transmission Customer has elected to self-supply this service for the portion of its Network Load served by energy scheduled for delivery from SEPA in connection with the SEPA Allocation specified in Section 3.0 above.

Schedule 6, Operating Reserve - Supplemental Reserve Service: The Transmission Customer must either purchase **Operating Reserve - Supplemental Reserve Service** from the Transmission Provider or make alternative comparable arrangements to satisfy its Operating Reserve - Supplemental Reserve Service obligations. The charges for this service are as provided per the Tariff, Schedule 6.

The Transmission Provider is providing reserves to Transmission Customer pursuant to Tariff Schedule 6 for 277 MWs of its ownership entitlement. As of the date of this agreement, charges for this service shall be calculated based upon 72 MWs which is the first contingency the Transmission Customer and the Transmission Provider include in their planning models. In addition, the Transmission Customer has elected to self-supply this service for the portion of its Network Load served by energy scheduled for delivery from SEPA in connection with the SEPA Allocation specified in Section 3.0 above.

- 6.5 Schedule 9, Loss Compensation Service: The Transmission Customer may elect to (1) supply the capacity and/or energy necessary to compensate the Transmission Provider for losses which occur across transmission facilities, (2) receive an amount of electricity at Delivery Points that is reduced by the amount of losses incurred by the Transmission Provider, or (3) with the concurrence of the Transmission Provider, have the Transmission Provider supply the capacity and/or energy necessary to compensate for such losses. To the extent the service is provided by the Transmission Provider, the charges for this service are as provided per the Tariff, Schedule 9.
- 6.6 Gross Receipts Tax:
Transmission Customer has demonstrated that its customers pay gross receipts taxes to the extent they presently apply. Transmission Provider will provide an ‘appropriate credit’ against the Tariff transmission rates, as referenced in Sections 6.1 through 6.4 above.
- 6.7 Redispatch Charges:
As per the Tariff, Part III Section 34.4.
- 6.8 Distribution Rates:
As provided per the Tariff (Part III, Section 34.6) and Attachment C hereto.
- 6.9 Penalties for Non-Compliance with the Transmission Provider’s Power Factor Standards:
As stated in Attachment D.
- 6.10 Schedule 13 Generator Imbalance Service
The Transmission Customer may elect to have this service if applicable. The charges / credits are provided per the Tariff, Schedule 13.
Charges / credits for Generator Imbalance service for the Transmission Customer shall be calculated using the Transmission Customer’s Ownership entitlements as defined in the 2005 Catawba Agreements as a proxy for the ‘output of the generator’ as stated in the first sentence of Tariff Schedule 13. The charges / credits are provided per the Tariff, Schedule 13.
- 7.0 Change in Control Area
- 7.1 Nothing in this Agreement shall be construed as requiring that Transmission Customer load remain part of the Transmission Provider’s control area load for the duration of this Agreement. Transmission Customer retains the right to arrange for its load to become a part of the electrical control area of another

control area operator during the term of this Agreement, should Transmission Customer determine such action to be in its best interest.

- 7.2 The Transmission Provider will assist Transmission Customer in identifying technical requirements for accomplishing a transfer by Transmission Customer of its load to a different electrical control area (e.g., through dynamic scheduling) and will agree to amend this Agreement, as and to the extent necessary, to accommodate such a transfer.

Attachment B Delivery Points

Delivery Locations:

Abbeville #1
Abbeville #2
Clinton #1
Clinton #2
Easley #1
Easley #3
Easley #4A
Easley #4B
Easley #5
Easley #6
Gaffney #1 A&B
Gaffney #2
Greer #2 A&B
Greer #3 A&B
Greer #4 A&B
Greer #5 A&B
Greer #6
Greer #7 A&B
Greer #8 A&B
Laurens #3
Laurens #4 A&B
Laurens #5 A&B
Laurens #6
Newberry #5 A&B
Newberry 6 A&B
Rock Hill #5
Rock Hill #6
Rock Hill #7 A&B
Rock Hill #8
Rock Hill #9
Rock Hill #10
Rock Hill #11
Rock Hill #12
Rock Hill #13
Rock Hill #14
Westminster #1

Attachment C Distribution Rates

Distribution Rates for Transmission Customer Delivery Points = (Specified Cost of Delivery Station) x (% Assigned to Transmission Customer) x 0.84% per month

Specified Cost of Delivery Station

For all assets in service as of January 1, 2006, the Specified Cost of the Delivery Station shall be the values specified in this attachment. The Specified Cost of all additional assets shall be the asset cost as assigned to FERC accounts 360 through 369 (or their successors). Retired assets will reduce the 'Specified Cost of Delivery Station' by the values of the retired assets which were included in the 'Specified Cost of Delivery Station'.

Percentage Assigned to Transmission Customer

This factor will apply to delivery stations only where the Transmission Customer is not the sole user. (For stations having the Transmission Customer as the sole user the value assigned to the factor will be one (1).)

For delivery stations in service on January 1, 2006, to which no new assets have been added, the factor is determined by the Percentage Use of Station Capability ("Percentage of Capability Method"). The Percentage Use of Station Capability formula is as follows:

The higher of

$$\text{Percentage Use Of Station Capability} = \text{Transmission Customer Contract kVA} / \text{Delivery Station kVA}$$

where

$$\text{Transmission Customer Contract kVA} = \text{Contract kW}^2 / \% \text{ Power Factor (Maximum Non-coincident 12 Month Peak)}^3$$

or

$$\text{Percentage Use Of Station Capability} = \text{Transmission Customer kW Peak 60 Minute Integrated Clock Hour Demand} / \text{Delivery Station kW}$$

where

$$\text{Delivery Station kW} = \text{Delivery Station kVA} \times \% \text{ Power Factor (Maximum Non-coincident 12 Month Peak)}$$

² Contract kW is equivalent to the term *Planned Demand* located on the 'Delivery Point Data Sheet'

³ % Power Factor (Maximum Non-coincident 12 Month Peak): This value is established on the date of the contract and is based on then current measurement data of the Delivery Point

For new Delivery Stations placed in service after January 1, 2006, and for Delivery Stations where new assets have been added⁴, the factor is determined by Percentage of Station Use ('Percentage of Station Use Method') as follows:

$$\text{Percentage of Station Use} = \frac{\text{Transmission Customer Integrated 60 Minute kW Demand at Hour of Delivery Station Peak}}{\text{Delivery Station Integrated 60 Minute kW Demand at Hour of Delivery Station Peak}}$$

The hour of the Delivery Station Peak is the hour of maximum delivery station integrated 60 minute demand for the current month and previous 11 months. Temporary load shifts and other unusual circumstances will be excluded from the Delivery Station Peak calculation. If metering is not in place to determine the hour of the delivery station peak, the Percentage of Capability Method shall be used.

These distribution rates do **NOT** include the costs for metering and metering equipment.

A Delivery Point may be terminated by either Transmission Provider or Transmission Customer upon reasonable notice.⁵ In the event that the termination of the Delivery Point results in the Early Retirement (as defined in Section 3.a below) of any of the Transmission Provider's facilities covered by these distribution rates or any of the Transmission Customer's facilities interconnected with such Transmission Provider's facilities, the Transmission Provider or the Transmission Customer, as applicable, shall be responsible for paying to the other party a Loss Due to Early Retirement ("LDER") calculated as follows:

1. If Transmission Provider is the initiator of the termination of the Delivery Point, Transmission Provider shall be responsible for paying to Transmission Customer any LDER incurred by Transmission Customer involving Transmission Customer's facilities interconnected with Transmission Provider's facilities at the Delivery Point. In such event, Transmission Customer's LDER shall consist of the sum of (a) the net book value of the Transmission Customer's facilities interconnected with Transmission Provider's facilities at the Delivery Point, plus actual cost of removal, less any actual salvage value, all as calculated using Transmission Customer's standard accounting practices, and (b) Transmission Customer's Reintegration Costs.

⁴ The definition of a new asset will be limited to

- a. The addition or replacement of transformers, capacitors, isolating devices and instrument transformers (non-meter application), or
- b. A cumulative increase in the original cost of a Delivery Point to 125% of its initial value.

⁵ For purposes of this Attachment C, "termination" of a Delivery Point means the Transmission Customer's permanent removal of all load from the point of electrical connection or at the voltage specified in the Delivery Point Data Sheet in effect for that Delivery Point immediately prior to the load removal.

Reintegration Costs shall include the direct labor costs (plus a reasonable percentage for regular employee fringe benefits and a reasonable percentage for engineering and supervision, cost of use of equipment, cost of materials, and miscellaneous expenses) that Transmission Customer incurs in connecting, by the most practical and direct route, (a) the Transmission Customer's lines that were previously connected with the terminated Delivery Point with (b) the Delivery Point that replaces the terminated Delivery Point. Reintegration Costs will be calculated consistent with the standard methodology being used by the Transmission Customer at that time for calculations of this kind.

2. If Transmission Customer is the initiator of the termination of the Delivery Point, Transmission Customer shall be responsible for paying to Transmission Provider any LDER incurred by Transmission Provider involving the Transmission Provider facilities covered by these distribution rates. In such event, Transmission Provider's LDER shall consist of the net book value of the Transmission Provider's facilities covered by these distribution rates, plus actual cost of removal, less any actual salvage value, all as calculated using Transmission Provider's standard accounting practices.
3. Definitions
 - a. A retirement shall be deemed to result in an "Early Retirement" for LDER purposes if the LDER, calculated as set forth in sections 1 and 2 herein, exceeds 20% of the sum of (a) the original cost of the asset(s) (including any additions or retirements) for which the LDER is calculated (b) actual removal costs, and (c), in the case of a termination initiated by the Transmission Provider, Reintegration Costs.
 - b. For LDER calculation purposes, "net book value" of an asset represents the original cost of the asset (including any additions or retirements) less actual accumulated depreciation for the asset as reflected in the fixed assets system of the impacted entity.
4. Billing Provisions. After the Delivery Point is terminated, the Transmission Provider or Transmission Customer, as applicable, shall render a bill to the other party for the Transmission Provider's or Transmission Customer's LDER (excluding the actual cost of removal and actual salvage value), and, if applicable, the Transmission Customer's Reintegration Costs. After the facilities at the Delivery Point have been removed, the Transmission Provider or Transmission Customer, as applicable, shall render a bill to the other party for the Transmission Provider's or Transmission Customer's actual cost of removal and actual salvage value. Bills rendered hereunder shall be subject to the Billing and Payment provisions of Section 7 of the Tariff.

Delivery Locations	Specified Cost as of August 1, 2026
Abbeville #1	\$51,712
Abbeville #2	\$0
Clinton #1	\$336,662
Clinton #2	\$0
Easley #1*/**	\$321,893
Easley #3	\$382,761
Easley #4A	\$633,002
Easley #4B	\$0
Easley #5	\$0
Easley #6	\$0
Gaffney #1A & B	\$603,700
Greer #2A & B	\$489,922
Greer #3A & B	\$0
Greer #4A & B	\$0
Greer #5A & B	\$0
Greer #6*/**	\$1,056,053
Greer #7A & B	\$0
Greer #8A & B	\$0
Laurens # 3	\$273,344
Laurens #4A & B	\$0
Laurens #5A & B	\$0
Laurens #6	\$0
Newberry #5A & B	\$0
Newberry #6A & B	\$0
Rock Hill #5	\$0
Rock Hill #6	\$0
Rock Hill #7A & B	\$0
Rock Hill #8	\$0
Rock Hill #9	\$0
Rock Hill #10	\$0
Rock Hill #11	\$0
Rock Hill #12	\$0
Rock Hill #13	\$0
Rock Hill #14	\$0
Westminster #1	\$0

* Denotes delivery stations for which Transmission Customer is not the sole user.

** Denotes delivery stations for which the total cost of the station is shown and not what is billed.

Attachment D Power Factor Penalty

1.0 Power Factor Compliance Requirements per Delivery Point

Beginning with the billing period which follows the later of: i) November 1, 2026, or ii) the month in which Transmission Provider complies with the requirements set forth in the Transmission Provider's Facility Connection Requirements ("FCR"), the Transmission Customer must meet the power factor requirements set forth in the FCR or pay penalties specified in Section 2.0 herein.

The Transmission Provider will provide power factor information for each Transmission Provider's Electric Distribution substation to demonstrate compliance with the power factor standards set forth in the FCR. If the Transmission Provider's Electric Distribution substations are not in compliance with the power factor standards set forth in the FCR, the Transmission Customer will not be subject to these power factor penalties until such time as the Transmission Provider has demonstrated that Transmission Provider's Electric Distribution substations are in compliance with the power factor standards.

Power Factor Groups are defined in the FCR.

2.0 Penalty Formula

The penalties for failure to meet the power factor requirements are provided:

Power Factor Groups consisting of 1 Delivery Point:

Peak Period Penalty = {Delivery Point kVar Demand at Peak – (Delivery Point kW Demand at Peak X 0.2718)} X \$0.75/kVar

Valley Period Penalty = Delivery Point Leading kVar Demand at Valley X \$0.75/kVar

Power Factor Groups consisting of 2 or more Delivery Points:

Peak Period Penalty:

Scenario 1: The aggregate power factor of the group is less than 96.5% lagging at the hour of monthly transmission system peak. The following penalty will be assessed.

Peak Period Group Penalty = {Delivery Group kVar Demand at Peak – (Delivery Group kW Demand at Peak X 0.2718)} X \$0.75/kVar

Scenario 2: The aggregate power factor of the group meets the power factor requirement at the hour of monthly transmission system peak but one or more Delivery Points in the group are operated at a power factor outside the 92% lagging to 92% leading range. Each Delivery Point with a power factor outside the desired power factor range will be assessed the following penalty.

Peak Period Penalty Per Delivery = {Delivery Point kVar Demand at Peak– (Delivery Point kW Demand at Peak X 0.2718)} X \$0.75/kVar

Scenario 3: The aggregate power factor of the group is less than 96.5% lagging at the hour of monthly transmission system peak and one or more Delivery Points in the group are operated at a power factor outside the 92% lagging to 92% leading range. The following penalty for the group and for each delivery will be assessed.

Peak Period Group Penalty = {Delivery Group kVar Demand at Peak– (Delivery Group kW Demand at Peak X 0.2718)} X \$0.75/kVar

Peak Period Penalty Per Delivery = {Delivery Point kVar Demand at Peak– (Delivery Point kW Demand at Peak X 0.2718)} X \$0.75/kVar

Total Peak Period Penalty = Peak Period Group Penalty + $\sum_{i=1}^n$ Peak Period Penalty Per Delivery_i

Where n is the total number of Delivery Points in the group in violation of the power factor requirements.

Valley Period Penalty:

Scenario 1: The aggregate power factor of the group is leading at the hour of monthly transmission system valley. The following penalty will be assessed.

Valley Period Group Penalty = Delivery Group Leading kVar Demand at Valley X \$0.75/kVar

Scenario 2: The aggregate power factor of the group meets the power factor requirement at the hour of monthly transmission system valley but one or more Delivery Points in the group are operated at a power factor outside the 92% lagging to 92% leading range. Each Delivery Point with a power factor outside the desired power factor range will be assessed the following penalty.

Valley Period Penalty Per Delivery = Delivery Point Leading kVar Demand at Valley X \$0.75/kVar

Scenario 3: The aggregate power factor of the group is leading at the hour of monthly transmission system valley and one or more Delivery Points in the group are operated at a power factor outside the 92% lagging to 92% leading range. The following penalty for the group and for each delivery will be assessed.

Valley Period Group Penalty = Delivery Group Leading kVar Demand at Valley X \$0.75/kVar

Valley Period Penalty Per Delivery = Delivery Point Leading kVar Demand at Valley X \$0.75/kVar

$$\text{Total Valley Period Penalty} = \text{Valley Period Group Penalty} + \sum_{i=1}^n \text{Valley Period Penalty} \\ \text{Per Delivery}_i$$

Where n is the total number of Delivery Points in the group in violation of the power factor requirements.

3.0 Terms

Delivery Point kW Demand at Peak - The kW demand at the Delivery Point registered at the hour of the Transmission Provider's Monthly Transmission System Peak

Delivery Group kW Demand at Peak - The sum of kW demand registered at the hour of the Transmission Provider's Monthly Transmission System Peak at each Delivery Point in the Delivery Point Group

Delivery Point kVar Demand - The kVar demand at the Delivery Point registered at the hour of the Transmission Provider's Monthly Transmission System Peak

Delivery Group kVar demand at Peak - The sum of kVar demand registered at the hour of the Transmission Provider's Monthly Transmission System Peak at each Delivery Point in the Delivery Point Group.

Delivery Point Leading kVar Demand at Valley - The kVar demand at the Delivery Point registered at the hour of the Transmission Provider's Monthly Transmission System valley

Delivery Group Leading kVar Demand at Valley - The sum of kVar demand registered at the hour of the Transmission Provider's Monthly Transmission System valley at each Delivery Point in the Delivery Point Group.

4.0 Transmission Provider Capacitors in Delivery Stations

The Delivery Point kVar Demand at Peak and the Delivery Point Leading kVar Demand at Valley will account for the presence of capacitors (if any) owned by Transmission Provider at the distribution delivery station. To prevent penalizing the Transmission Customer for Transmission Provider's operation of its capacitors, the Transmission Provider capacitors will be considered operational during the day and hour of the monthly transmission system peak regardless of the actual operating status of the Transmission Provider capacitors. Likewise, the Transmission Provider capacitors will be considered not operational during the day and hour of the monthly transmission system valley regardless of the actual operating status of the Transmission Provider capacitors.

5.0 Temporary Waiver of Power Factor Requirements for New Delivery Points

The Transmission Customer may request a 24-month partial waiver of the Peak Period Power Factor requirements for new Delivery Points. This waiver would be to allow the transmission customer adequate time to develop a new distribution voltage profile for the

new Delivery Point and to perform the associated feeder work. The form of the partial waiver would be as follows:

1. For the first 12-month period following the in-service date of the new delivery, the Peak Period Power Factor requirements for that delivery will be:

Peak Periods - The Transmission Customer must operate its electrical system in a manner resulting in a power factor not less than 90% lagging as measured at the Delivery Point at the hour of transmission system peak on a monthly basis for the months of June, July, August, and September. A lagging power factor of less than 90% lagging as measured at the Delivery Point at the hour of transmission system peak for the specified months will result in a penalty. The penalty will be calculated using the following formula:

$$\text{Peak Period Penalty} = \{ \text{Delivery Point kVar Demand at Peak} - (\text{Delivery Point kW Demand at Peak} \times 0.4843) \} \times \$0.75/\text{kVar}$$

2. For the second 12-month period following the in-service date of the new delivery, the Peak Period Power Factor requirements for that delivery will be:

Peak Periods - The Transmission Customer must operate its electrical system in a manner resulting in a power factor not less than 94% lagging as measured at the Delivery Point at the hour of transmission system peak on a monthly basis for the months of June, July, August, and September. A lagging power factor of less than 94% lagging as measured at the Delivery Point at the hour of transmission system peak for the specified months will result in a penalty. The penalty will be calculated using the following formula:

$$\text{Peak Period Penalty} = \{ \text{Delivery Point kVar Demand at Peak} - (\text{Delivery Point kW Demand at Peak} \times 0.3629) \} \times \$0.75/\text{kVar}$$

3. The new Delivery Point cannot be included in a power factor group.

6.0 Waiver of Valley Power Factor Requirements for Delivery Points serving Underground Distribution Systems

The Transmission Customer may request a waiver from the Valley Period Power Factor requirement for any Delivery Point dedicated to serving an underground distribution system. Transmission Provider recognizes that such systems may be capacitive in nature at minimum loads and may present a leading power factor at the Delivery Point. In requesting this waiver, the Transmission Customer must demonstrate that the Delivery Point is capacitive in nature at minimum loads and that no capacitors are in-service at such times. If the Delivery Point receives a waiver it cannot be included in a power factor group.

Attachment E

Network Operating Agreement

1.0 Control Area Requirements

The Transmission Customer shall: (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Corporation (“NERC”), SERC Reliability Corporation (“SERC”), (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider; or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with other entities, consistent with Good Utility Practice, which satisfies NERC and SERC requirements. The Transmission Customer shall plan, construct, operate and maintain its facilities and system in accordance with Good Utility Practice, which shall include, but not be limited to, all applicable guidelines of NERC and SERC as they may be modified from time to time, and any generally accepted practices in the region.

2.0 Network Operating Committee

(a) The Transmission Provider and the Transmission Customer each shall appoint a member and an alternate to a Network Operating Committee, and so notify the other Party of such appointment in writing. Such appointments may be changed at any time by similar notice. Each member and alternate shall be a responsible person working with the day to day operations of their respective system. The Network Operating Committee shall meet as necessary to carry out the duties set forth herein. The Network Operating Committee shall represent the Parties in all operational matters that may be delegated to it by mutual agreement of the Parties. The Network Operating Committee shall hold meetings at the request of either Party, at a time and place agreed upon by the members of the Network Operating Committee.

(b) The Network Operating Committee shall coordinate operating criteria for the Parties’ respective responsibilities under the Tariff and this Service Agreement including: (i) operation and maintenance of the Parties’ facilities and equipment necessary for integrating the Transmission Customer within the Transmission Provider’s Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment); (ii) transfer of data, as necessary and as applicable, between the Transmission Provider and the Transmission Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider’s Transmission System, interchange schedules, unit outputs for redispatch required under Section 33 of the Tariff, voltage schedules, loss factors and other real time data); (iii) use of software programs required for data links and constraint dispatching; (iv) exchange of data on forecasted loads and resources necessary for long-term planning; (v) develop a procedure under which the Transmission Provider will report to the Transmission Customer the ongoing compliance status of the Transmission Provider Electric Distribution substations with the power factor requirements set forth in the FCR subject to the terms and conditions of the

Service Agreement Attachment D, Section 1.0; and (vi) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Committee shall have no power to amend or alter the provisions of this Service Agreement. The Network Operating Committee shall use the standards set forth in FCR, as may be amended from time to time. The Network Operating Committee shall establish procedures: (i) to establish and verify initial and continuous compliance with the FCR, including the implementation of revised FCR provisions; and (ii) to correct failures to comply in a timely manner. The Network Operating Committee shall use the standards set forth in the Transmission Provider's FCR document as may be amended from time to time.

3.0 Network Operating Committee Agreements

(a) Each Party shall cooperate in providing to the Network Operating Committee all information required in the performance of the Network Operating Committee's duties. All decisions and agreements, if any, made by the Network Operating Committee shall be evidenced in writing, approved by each member of the Operating Committee, and shall be in accordance with the Tariff, and this Service Agreement.

(b) Disputes within the Network Operating Committee shall be resolved in accordance with the Dispute Resolution Procedures in the Tariff.

4.0 Redispatch Procedures

(a) The Transmission Provider may implement redispatch procedures in accordance with Section 33.2 of the Tariff. If the Transmission Provider has redispatch procedures that have been accepted for filing and permitted to go into effect by the Federal Energy Regulatory Commission ("FERC" or the "Commission"), those procedures will be adhered to by the Transmission Provider and the Transmission Customer in any instance in which redispatch is implemented. Until such time as the FERC has permitted the Transmission Provider's redispatch procedures to go into effect, redispatch will require mutual consent by both the Transmission Provider and the Transmission Customer. The Transmission Customer shall respond immediately to requests for redispatch from the Transmission Provider's system operator.

(b) The Transmission Customer will submit to the Transmission Provider verifiable cost data for its Network Resources, which estimates the cost to the Transmission Customer of changing the generation output of each of its Network Resources. This cost data will be used, along with similar data for the Transmission Provider's resources, as the basis for least-cost redispatch. The Transmission Provider's operations personnel will keep this data confidential, and will disclose it only to those who require the information in order to carry out the redispatch function. Under no circumstances shall the Transmission Provider disclose this data to the Transmission Provider's merchant function or any other marketer. If the Transmission Customer experiences changes to its costs, the Transmission Customer will submit those changes to the Transmission Provider's system operator.

- (c) The Transmission Customer may audit, at its own expense, redispatch events (such as the cause or necessity of the redispatch) during normal business hours following reasonable notice to the Transmission Provider. Either the Transmission Customer or the Transmission Provider may request an audit of the other Party's cost data. Any audit of cost data will be performed by an independent agent at the requesting Party's cost. Such independent agent will be required to keep all cost data confidential.
- (d) Once redispatch has been implemented, the Transmission Provider will book in a separate account the redispatch costs incurred by the Transmission Provider and the Transmission Customer based on the submitted cost data. The Transmission Provider and all Transmission Customers will each bear a proportional share of the total redispatch costs based on their then-current Load Ratio Shares. The redispatch charge or credit, as appropriate, will be reflected on the Transmission Customer's monthly bill.

5.0 Metering

- (a) The Transmission Customer will be responsible for the purchase, installation, operation, maintenance, repair, and replacement of all metering equipment necessary to provide Network Integration Transmission Service, except as otherwise set forth in this Attachment E. All metering equipment of the Transmission Customer shall conform to Good Utility Practice and the standards and practices of the Transmission Provider's Control Area where necessary for implementation of Network Integration Transmission Service. Prior to its installation, the Transmission Provider and the Transmission Customer shall review the metering equipment to ensure conformance with such standards or practices, as applicable. The Transmission Customer may, by mutual agreement of the Parties, lease or purchase metering equipment of the Transmission Provider for all or part of this obligation.
- (b) The Parties have entered into a separate agreement the Catawba Nuclear Station Joint Operating Support Agreement FERC Electric Rate Schedule No. 313 dated June 7, 2005 and effective January 1, 2006, between Transmission Customer and Duke Energy Carolinas, LLC (the "Meter Agreement") that specifies how Transmission Customer may satisfy the obligations set out in Section 5.0(a), above.
- (c) Electric capacity and energy received by the Transmission Provider directly from the Transmission Customer's Network Resources will be measured by meters installed at the Transmission Customer's Network Resources. Electric capacity and energy which are wheeled for the Transmission Customer by a neighboring system will be received at designated Points of Receipt between such neighboring system and the Transmission Provider Control Area. When measurement is made at any location other than a Point of Receipt, suitable adjustment for losses between the point of measurement and the Point of Receipt will be agreed upon in writing between the Parties hereto and will be applied to all measurements so made. Metered receipts used in billing and accounting hereunder will in all cases include adjustments for such losses.
- (d) Electric capacity and energy delivered to the Transmission Customer's Network Load by the Transmission Provider will be measured at the Delivery Points to such

Network Load. The meters may be located at other than the Delivery Point by mutual agreement of the Parties or the Operating Committee. When measurement is made at any location other than at a Delivery Point, suitable adjustment for losses between the point of measurement and the Delivery Point will be agreed upon in writing between the Parties hereto and will be applied to all such measurements so made. Metered receipts used in billing and accounting hereunder will in all cases include adjustments for such losses. In addition, the Transmission Customer will provide written confirmation of its commitment not to tap a transmission line before a meter without sixty (60) days' advance notification to the Transmission Provider. Further, the Transmission Customer will allow the Transmission Provider access to its facilities for inspection of the transmission line upon the Transmission Provider's reasonable notice.

(e) Meters at the Transmission Customer's Network Resources, where applicable, and Network Load will be tested at least biennially irrespective of ownership. Representatives of the non-owning Party will be provided notification of and afforded an opportunity to witness such tests.

(f) The owning Party will, upon request of the non-owning Party, test any meter at the Network Resources or Network Load used for determining the receipt or delivery of capacity and energy by the Transmission Provider. In the event the test shows the meter to be inaccurate, the owning Party will make any necessary adjustments, repairs, or replacements thereto. In the event the test shows the meter to be accurate, all costs of the test will be paid by the non-owning Party.

(g) In the event any meter used to measure capacity and energy fails to register or is found to be inaccurate, appropriate billing adjustments, based on the best information available, will be agreed upon by the Parties hereto. Meters shall be calibrated to 0.5% accuracy at unity power factor for both full load and light load. These meters shall be calibrated to 1.0% accuracy for 0.5 power factor at full load. Metering accuracy limits are stated in the following table.

METER ACCURACY LIMITS			
Watt-hour Function			Var-hour
Full Load	Power Factor	Light Load	Power Factor
+/- 0.5	+/- 1.0	+/- 0.5	+/- 1.0

Notes:

- Watt-hour and var-hour functions should be tested in both directions of energy flow (In and Out).
- When compensating for transformer or line loss, utilize stated limits above or 5% of desired compensation, whichever is greater.
- The meter shall be tested with compensation applied to obtain a true test of the installation.

<i>Test Points</i>	<i>Volts</i>	<i>Amps</i>	<i>Power Factor</i>
Full Load	120	5	1.0
Power Factor	120	5	0.5
Light Load	120	0.5	1.0

These values will be considered to be correct and accurate insofar as correction of billing is concerned. If, as a result of any test, a meter is found to be out of compliance with these values, then the record of readings of such meter previously taken will be corrected according to the percentage of any inaccuracy so found, but no correction will extend beyond ninety (90) days prior to the day on which inaccuracy is discovered by such test.

(h) The Transmission Provider will have the right to install, at its own expense, suitable metering equipment at any Delivery Point, as herein provided for the purpose of checking the meters installed by the Transmission Customer.

(i) Description of Metering Equipment

The Transmission Customer, at its own expense, will furnish and install any equipment required to provide the metering and communication as described in Section 5.0(a) and the Meter Agreement. The Transmission Provider will have access to the meters for the purpose of collecting and processing meter data for billing under the Tariff. The Transmission Provider will also have access to the meters for the purpose of verifying the accuracy of the metered data and meter configuration.

(j) The Party that owns a meter will provide any equipment nameplate and configuration information requested by the non-owning Party to allow the non-owning Party to verify that the meter measurement, and loss compensation calculation if applicable, is accurate. The owning Party shall notify the non-owning Party at least thirty (30) days in advance of any changes to the metering, meter programming or meter equipment. In the event that changes are made in response to equipment failure, notification will be made within two (2) business days after the failure is discovered.

6.0 Control Area and Data Equipment

(a) The Transmission Customer will be responsible for the purchase, installation, operation, maintenance, repair, and replacement of all data acquisition equipment, metering equipment, protection equipment, and any other associated equipment and software, which may be required for the Transmission Customer to operate in accordance with Section 3.0 of this Attachment E. Such equipment shall conform to Good Utility Practice and conform to the reasonable standards and practices of the Transmission Provider's Control Area, provided that such standards and practices are applied by the Transmission Provider on a consistent and non-discriminatory basis to all Transmission

Customers. Prior to its installation, the Transmission Provider and the Transmission Customer shall review the equipment and software required by this Section to ensure conformance with such standards or practices.

(b) The real time telemetry and data to be received by the Transmission Provider's system operator and the Transmission Customer shall be determined initially by the Parties. Subsequent changes shall be determined by the Network Operating Committee. Such telemetry and data shall be necessary for monitoring of system operations for reliability, security or economics. Such telemetry may include but is not limited to loads, line flows, voltages, and breaker status at any of the Transmission Customer's transmission facilities, and Transmission Customer owned generator output. All such determinations under this subsection (b) shall be in accordance with Good Utility Practice. To the extent telemetry is required that is not available on the Transmission Customer's facilities, the Transmission Customer, at its own expense, shall install any metering equipment, data acquisition equipment, or other equipment and software on its system that is necessary for the telemetry to be received by the Transmission Provider's system operator.

(c) Each party shall be responsible for implementing any computer modifications or changes required to its own computer system(s) as necessary to implement this Section.

(d) The Transmission Customer will be responsible for the provision of scheduling information (including the calculation of any dynamic information used for scheduling and for any real-time modification of such dynamic scheduling information) necessary to coordinate the Transmission Customer's supply of energy from Network Resources and non-designated Network Resources which may be scheduled from time to time to serve a portion of the Transmission Customer's Network Load.

(e) To the extent that data required to determine the scheduling information pursuant to Section 6.0(d), above, are not available for whatever reason (*e.g.*, meter failure or communications failure), or based on reasonable engineering judgment are deemed inaccurate, the Transmission Customer may use reasonable procedures, consistent with Good Utility Practice, to estimate such unavailable or inaccurate data.

(f) The dynamic scheduling arrangements will be deemed to be in a state of successful operation if the dynamic scheduling information necessary for system operations is being made available to the Transmission Provider and other entities as required by agreement of the Parties ('Successful Operation'). The Parties agree that because of technical operating realities, Successful Operation will not result in the dynamic scheduling information being one hundred percent (100%) accurate. The Parties agree, however, that so long as the dynamic scheduling arrangements yield dynamic scheduling information that appears to the operating representatives of the Parties to be adequate for continuing operational purposes, the state of Successful Operation shall be deemed to exist. If sudden discontinuities or other atypical trends appear in the dynamic scheduling information which cause either Party's system operator to question the operational validity of such information, the Transmission Customer may, on its own initiative, and shall, at the request of the Transmission

Provider, investigate the cause of the observed discontinuities or atypical trends. If such investigation reveals a condition that the Parties agree renders the dynamic scheduling information inadequate for continuing operational purposes, the dynamic scheduling arrangements will be deemed inoperable from the time the condition is determined to have first occurred, or absent the ability to make a determination at the time the investigation was initiated, until the condition is resolved.

7.0 Operating Requirements

(a) The Transmission Customer shall operate, or cause to be operated, its generating resources in a manner consistent with that of the Transmission Provider following voltage schedules, utilizing free governor response, meeting power factor requirements at the points of interconnection with the Transmission Provider's system, and other such criteria required by NERC or SERC, or any of their successors and consistently adhered to by the Transmission Provider.

(b) Insofar as practicable, the Transmission Provider and the Transmission Customer shall protect, operate, and maintain their respective systems so as to avoid or minimize the likelihood of disturbances which might cause impairment of service on the system(s) of the other. The Parties, consistent with Good Utility Practice, shall implement load shedding programs to maintain the reliability and integrity of the Transmission System, as provided in Section 33.6 of the Tariff. Load shedding shall include automatic load shedding by underfrequency relay or manual load shedding. The Transmission Provider will implement load shedding to maintain the relative sizes of load served by the affected facilities, unless otherwise required by circumstances beyond the control of the Transmission Provider or the Transmission Customer. Automatic load shedding devices will operate without notice. When manual load shedding is relied upon, the Transmission Provider shall notify the Transmission Customer's dispatchers or schedulers of the required action and the Transmission Customer shall take immediate steps to comply.

(c) The Transmission Customer shall, at its own expense, provide, operate, and maintain in service high-speed, underfrequency load shedding equipment consistent with NERC and SERC, or any of their successor's requirements. The Transmission Customer will install underfrequency relays to disconnect automatically approximately thirty percent (30%) of its Network Load in a manner consistent with that followed by the Transmission Provider, which is three steps of approximately ten percent (10%) each at frequency set points of 59.3 Hertz, 59.0 Hertz and 58.5 Hertz. The Parties agree that for purposes of automatic load shedding, the Transmission Customer's Network Load is covered under the Transmission Provider's existing underfrequency relay systems. At this time, no additional underfrequency relays on the Transmission Customer's facilities are necessary. The installation on the Transmission Customer's facilities of underfrequency relays to accomplish any additional load shedding above that already installed shall be completed on a schedule agreed to by the Network Operating Committee. The Network Operating Committee may review the amount of load that would be disconnected automatically and make such adjustments and changes as necessary.

(d) In the event the Transmission Provider modifies the load shedding system in accordance with Good Utility Practice, the Transmission Customer shall, at its expense, make changes to its equipment and setting of such equipment, as required. The Transmission Customer shall test and inspect the load shedding equipment within ninety (90) days of taking Network Integration Transmission Service under the Tariff and thereafter in accordance with Good Utility Practice, but no more often than the Transmission Provider, and provide a written report to the Transmission Provider. The Transmission Provider may request a test of the load shedding equipment with reasonable written notice at the expense of the Transmission Provider. If the Transmission Customer installs automatic load shedding equipment, the Transmission Provider shall provide to the Transmission Customer a written report upon each test of the Transmission Provider's automatic load shedding equipment. The Parties will provide each other with copies of NERC compliance reports, as they relate to the NERC Planning Standards on underfrequency load shedding.

8.0 Operational Information

(a) The Transmission Customer shall provide by September 1 of each year the Transmission Customer's Network Resource availability forecast (*e.g.*, all planned resource outages, including off-line and on-line dates) for the following year. Such forecast shall be made in accordance with Good Utility Practice. The Transmission Customer shall inform the Transmission Provider, in a timely manner, of any changes to the Transmission Customer's Network Resource availability forecast. In the event that the Transmission Provider determines, in compliance with its rights and responsibilities under the Tariff, that such forecast changes cannot be accommodated due to a transmission constraint on its Transmission System, then the Transmission Provider shall notify the Network Operating Committee which shall meet to resolve the matter. If the Network Operating Committee is unable to resolve the matter in a timely fashion, then the Dispute Resolution Procedures set forth in Section 12 of the Tariff shall apply.

(b) The Transmission Customer shall provide, at least thirty-six (36) hours in advance of every calendar day, the Transmission Customer's best forecast of any planned transmission or Network Resource outage(s) and other operating information reasonably required by the Transmission Provider to provide Transmission Service under the Service Agreement. In the event that such planned outages cannot be accommodated due to a transmission constraint on the Transmission Provider's Transmission System and the Network Operating Committee cannot agree on remedial measures, the provisions of Section 33 of the Tariff will be implemented.

(c) The Transmission Provider and the Transmission Customer shall notify and coordinate with the other Party prior to the commencement of any work by either Party (or contractors or agents performing on their behalf) which may directly or indirectly have an adverse effect on the other Party.

(d) All information provided by either Party to the other under this Section shall be treated as confidential.

9.0 Network Planning

In order for the Transmission Provider to plan, on an ongoing basis, to meet the Transmission Customer's requirements for Network Integration Transmission Service, the Transmission Customer shall provide to the Transmission Provider, by September 1st of each year, updated information (current year and 10-year projection) for Network Load and Network Resources, as well as any other information reasonably necessary for the Transmission Provider to plan for Network Integration Transmission Service. This type of information is consistent with the Transmission Provider's information requirements for planning to serve its Native Load Customers. The data will be provided in a format consistent with that used by the Transmission Provider.

11.0 Character of Service

Power and energy delivered under the Service Agreement shall be delivered as three-phase alternating current at a frequency of approximately 60 Hertz, and at the nominal voltages at the Delivery and Receipt points.

12.0 Transfer of Power and Energy Through Other Systems

Since the Transmission Provider's Transmission System is, and will be, directly and indirectly connected with other electric systems, it is recognized that, because of the physical and electrical characteristics of the facilities involved, power delivered under the Service Agreement will flow through such other systems. The Parties agree to advise other electric systems as deemed appropriate of such scheduled transfers and to attempt to maintain good relationships with affected third parties. The Parties further agree that the Transmission Customer or its duly appointed agent, will be responsible for making appropriate arrangements, consistent with the Tariff, for: (i) the scheduling and delivery of that portion of power and energy from the designated Network Resource within the Southern Company Control Area to the Transmission Provider's Control Area; and (ii) any other transmission provider as necessary for the scheduling and delivery of power and energy from any other designated or non-designated Network Resources of the Transmission Customer to the Transmission Provider's Control Area.

Attachment F
Other Charges/Credits

Pursuant to Order 890, Transmission Customer has requested credit for a transmission line built by Transmission Customer, that had it been built by the Transmission Provider, would have been included into the Transmission Provider's transmission rate base.

A monthly credit of \$4,445 will be issued to Transmission Customer.