INFORMATION SHEET

PRESIDING: Chair Mitchell, Presiding; and Commissioners Brown-Bland, Gray, and Clodfelter
PLACE: Dobbs Building, Room 2115, Raleigh, NC
DATE: Tuesday, September 10, 2019
TIME: 9:00 a.m. to 11:44 a.m.
DOCKET NO.: E-2, Sub 1204
COMPANIES: Duke Energy Progress, LLC
DESCRIPTION: Application of Duke Energy Progress, LLC Pursuant to N.C.G.S. § 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities
VOLUME NUMBER: 2

APPEARANCES
Please see attached.

WITNESSES
Please see attached.

EXHIBITS

Please see attached.

EMAIL DISTRIBUTION

TRANSCRIPT COPIES ORDERED: Downey, Thompson, West and Smith
CONFIDENTIAL EXHIBITS: Downey, Thompson, West and Smith
REPORTED BY: Joann Bunze
DATE FILED: October 3, 2019

TRANSCRIPT PAGES: 138
PREFILED PAGES: 64
TOTAL PAGES: 202

PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, September 10, 2019

TIME: 9:00 a.m. - 11:44 a.m.

DOCKET NO.: E-2, Sub 1204

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

Application of Duke Energy Progress, LLC

Pursuant to N.C.G.S. 62-133.2 and NCUC Rule R8-55

Regarding Fuel and Fuel-Related Cost Adjustments for

Electric Utilities

VOLUME: 2

Noteworthy Reporting Services, LLC

A P P E A R A N C E S:

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FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES, II:

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Senior Attorney
Tirrill Moore, Esq.
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

FOR FAYETTEVILLE PUBLIC WORKS COMMISSION:
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General Counsel
955 Old Wilmington Road
Fayetteville, North Carolina 28301

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
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Regulatory Counsel
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Raleigh, North Carolina 27609

A P P E A R A N C E S Cont'd.:

FOR THE USING AND CONSUMING PUBLIC:

Dianna W. Downey, Esq.
North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 9/9/19 DOCKET NO.: E-2, Sub 1204

ATTORNEY NAME and TITLE: Jack Jirak + Dwight Allen

FIRM NAME: ______

ADDRESS: 410 S. Wilmington St

CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARING FOR: DEP

APPLICANT: ✓ COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE 09/09/19 DOCKET #: E-2, Subs 1204, 1205, 1206 & 1207

NAME AND TITLE OF ATTORNEY Robert F. Page

FIRM NAME Crisp & Page PLLC

ADDRESS 4010 Barrett Dr., Suite 205

CITY Raleigh ZIP 27609

APPEARING FOR: Carolina Utility Customers Association, Inc.

APPLICANT ______ COMPLAINANT ______ INTERVENER ✓

PROTESTANT ______ RESPONDENT ______ DEFENDANT ______

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Signature: ______

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: **September 5, 2019** DOCKET NO. **E-2, 1204**

NAME AND TITLE OF ATTORNEY Ralph McDonald

FIRM NAME Bailey & Dixon, L.L.P.

ADDRESS Post Office Box 1351

CITY Raleigh, NC ZIP 27602-1351

APPEARING FOR: **Carolina Industrial Group for Fair Utility Rates II (CIGFUR II)**

APPLICANT ___ COMPLAINANT _____ INTERVENER _X_
PROTESTANT ___ RESPONDENT ____

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126360

NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 9/19/19 DOCKET NO.: E-2, Sub 1204

ATTORNEY NAME and TITLE: Gudrun Thompson

FIRM NAME: Southern Environmental Law Ctr.

ADDRESS: 601 W. Rosemary St, Ste 220

CITY: Chapel Hill STATE: NC ZIP CODE: 27516

APPEARING FOR: Sierra Club

APPLICANT:_____ COMPLAINANT:_____ INTERVENOR: ✓

PROTESTANT:_____ RESPONDENT:_____ DEFENDANT:_____

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Email: gudrunthompson@gmail.com

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 9/9/19 DOCKET NO.: E-2, Sub 1204

ATTORNEY NAME and TITLE: Mr. Tirrill Moore

FIRM NAME: Southern Environmental Law Center

ADDRESS: 601 W Rosemary, Suite 220

CITY: Chapel Hill STATE: NC ZIP CODE: 27516

APPEARING FOR: Sierra Club

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: ✓

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE: 9/9/2019 **DOCKET NO.:** E-2 Subs 1204, 1205, 1206

ATTORNEY NAME and TITLE: Benjamin Smith, Regulatory Counsel

FIRM NAME: N/A

ADDRESS: 4800 Six Forks Road, Suite 300

CITY: Raleigh **STATE:** NC **ZIP CODE:** 27609

APPEARING FOR: NCSEA

APPLICANT: ___ **COMPLAINANT:** ___ **INTERVENOR:** ✓

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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NORTH CAROLINA UTILITIES COMMISSION
APPEARANCE SLIP

DATE: 09/09/2019 **DOCKET NO.:** E-2, Sub 1204

ATTORNEY NAME and TITLE: James West, General Counsel

FIRM NAME: Fayetteville Public Works Commission

ADDRESS: 955 Old Wilmington Road

CITY: Fayetteville **STATE:** NC **ZIP CODE:** 28301

APPEARING FOR: Fayetteville Public Works Commission

APPLICANT:_____ **COMPLAINANT:**_____ **INTERVENOR:** ✓

PROTESTANT:_____ **RESPONDENT:**_____ **DEFENDANT:**_____

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NORTH CAROLINA UTILITIES COMMISSION
PUBLIC STAFF - APPEARANCE SLIP

DATE September 9, 2019 DOCKET #: E-2, Sub 1204

PUBLIC STAFF MEMBER Dianna Downey

ORDER FOR TRANSCRIPT OF TESTIMONY TO BE **EMAILED** TO THE PUBLIC STAFF - PLEASE INDICATE YOUR DIVISION AS WELL AS YOUR EMAIL ADDRESS BELOW:

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GAS ______
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LEGAL dianna.downey@psncuc.nc.gov
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Dianna W. Downey

Signature of Public Staff Member

I/.

Duke Energy Process, LLC Fossil Fuel Procurement Practices

Coal

- Near and long-term coal consumption is forecasted based on inputs such as load projections, fleet maintenance and availability schedules, coal quality and cost, environmental permit and emissions considerations, projected renewable capacity, and wholesale energy imports and exports.
- Station and system inventory targets are developed to provide reliability, insulation from short-term market volatility, and sensitivity to evolving coal production and transportation conditions. Inventories are monitored continuously.
- On a continuous basis, existing purchase commitments are compared with consumption and inventory requirements to determine additional needs.
- All qualified suppliers are invited to participate in proposals to satisfy additional or contract needs.
- Spot market solicitations are conducted on an on-going basis to supplement contract purchases.
- Contracts are awarded based on the lowest evaluated offer, considering factors such as price, quality, transportation, reliability and flexibility.
- Delivered coal volume and quality are monitored against contract commitments. Coal and freight payments are calculated based on certified scale weights and coal quality analysis meeting ASTM standards as established by ASTM International.

Gas

- Near and long-term natural gas consumption is forecasted based on inputs such as load projections, commodity and emission prices, projected renewable capacity, and fleet maintenance and availability schedules.
- Physical procurement targets are developed to procure a cost effective and reliable natural gas supply.
- Over time, short-term and long-term Requests for Proposals and market solicitations are conducted with potential suppliers to procure the cost competitive, secure, and reliable natural gas supply, firm transportation, and storage capacity needed to meet forecasted gas usage.
- Short-term and spot purchases are conducted on an on-going basis to supplement term natural gas supply.
- On a continuous basis, existing purchases are compared against forecasted gas usage to ascertain additional needs.
- Natural gas transportation for the generation fleet is obtained through a mix of long term firm transportation agreements, and shorter term pipeline capacity purchases.
- A targeted percentage of the natural gas fuel price exposure is managed via a rolling 36-month structured financial natural gas hedging program.
- Through the Asset Management and Delivered Supply Agreement between Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC implemented on January 1, 2103, DEC serves as the designated Asset Manager that procures and manages the combined gas supply needs for the combined Carolinas gas fleet.

Fuel Oil

- No. 2 fuel oil is burned primarily for initiation of coal combustion (light-off at steam plants) and in combustion turbines (peaking assets).
- All No. 2 fuel oil is moved via pipeline to applicable terminals where it is then loaded on trucks for delivery into the Company's storage tanks. Because oil usage is highly variable, the Company relies on a combination of inventory, responsive suppliers with access to multiple terminals, and trucking agreements to manage its needs. Replenishment of No. 2 fuel oil inventories at the applicable plant facilities is done on an "as needed basis" and coordinated between fuel procurement and station personnel.
- Formal solicitations for supply may be conducted as needed with an emphasis on maintaining a network of reliable suppliers at a competitive market price in the region of our generating assets.

I/

DUKE ENERGY PROGRESS
Summary of Coal Purchases
Twelve Months Ended March 31, 2019 & 2018
Tons

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
1	April 2018	250,213	0	250,213
2	May	229,852	0	229,852
3	June	170,145	0	170,145
4	July	281,312	25,688	307,000
5	August	316,012	24,850	340,861
6	September	280,066	74,767	354,833
7	October	230,501	83,019	313,519
8	November	166,987	74,177	241,164
9	December	60,781	259,086	319,867
10	January 2019	148,090	170,562	318,652
11	February	314,005	25,352	339,357
12	March	402,153	24,070	426,223
13	**Total** (Sum L1:L12)	**2,850,117**	**761,571**	**3,611,686**

Line No.	Month	Contract (Tons)	Net Spot Purchase and Sales (Tons)	Total (Tons)
14	April 2017	223,875	0	223,875
15	May	224,952	0	224,952
16	June	238,854	12,264	251,118
17	July	320,213	0	320,213
18	August	430,436	0	430,436
19	September	346,651	0	346,651
20	October	325,000	0	325,000
21	November	324,889	0	324,889
22	December	229,150	0	229,150
23	January 2018	212,233	0	212,233
24	February	235,368	0	235,368
25	March	260,527	326	260,853
26	**Total** (Sum L14:L25)	**3,372,148**	**12,590**	**3,384,738**

DUKE ENERGY PROGRESS
Summary of Gas Purchases
Twelve Months Ended March 31, 2019 & 2018
MBTUs

Line No.	Month	MBTUs
1	April 2018	11,053,613
2	May	12,806,726
3	June	15,479,769
4	July	20,299,371
5	August	19,387,566
6	September	17,128,278
7	October	16,867,758
8	November	14,807,040
9	December	14,345,919
10	January 2019	13,375,182
11	February	13,994,322
12	March	12,831,035
13	**Total** (Sum L1:L12)	**182,376,579**

Line No.	Month	MBTUs
14	April 2017	11,260,572
15	May	11,466,510
16	June	13,517,327
17	July	15,763,956
18	August	15,138,794
19	September	13,928,655
20	October	12,729,705
21	November	14,540,861
22	December	16,817,106
23	January 2018	14,446,004
24	February	13,775,980
25	March	15,986,353
26	**Total** (Sum L14:L25)	**169,371,823**

I/

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1204

In the Matter of	)
Application of Duke Energy Progress, LLC	)
Pursuant to G.S. 62-133.2 and NCUC Rule	)
R8-55 Relating to Fuel and Fuel-Related	)
Charge Adjustments for Electric Utilities	)

BRETT PHIPPS CONFIDENTIAL EXHIBIT 3

FILED UNDER SEAL

JUNE 11, 2019

I/A

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Summary Comparison of Fuel and Fuel-Related Cost Factors
Test Period Twelve Months Ended March 31, 2019
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Exhibit 1

Line No.	Description	Reference	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
	Current Fuel and Fuel-Related Cost Factors (Approved Fuel Rider Docket No. E-2, Sub 1173)						
1	Approved Fuel and Fuel-Related Costs Factors	Input	2.311	2.556	2.477	1.757	2.251
2	EMF Increment / (Decrement)	Input	0.575	0.363	0.343	1.038	0.885
3	EMF Interest Decrement cents/kWh, if applicable	n/a	-	-	-	-	-
4	Approved Net Fuel and Fuel-Related Costs Factors	Sum	2.886	2.919	2.820	2.795	3.136
	Other Fuel and Fuel-Related Cost Factors						
5	NERC Capacity Factor of 91.8% with Projected Billing Period MWh Sales	Exh 2 Sch 3 pg 3	2.650	2.639	2.635	2.678	2.645
6	Proposed Nuclear Capacity Factor of 94.62% with Normalized Test Period MWh Sales	Exh 2 Sch 2 pg 3	2.604	2.614	2.615	2.643	2.515
	Proposed Fuel and Fuel Related Cost Factors using Proposed Nuclear Capacity Factor of 94.62% with Projected Billing Period MWh Sales						
7	Fuel and Fuel-Related Costs excluding Purchased Capacity cents/kWh	Exh 2 Sch 1 pg 2	2.217	2.314	2.309	2.020	2.120
8	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Exh 2 Sch 1 pg 2	0.138	0.155	0.123	0.079	0.001
9	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Sum	2.355	2.469	2.432	2.099	2.121
10	EMF Increment/(Decrement) cents/kWh	Exh 2 Sch 1 pg 2	0.252	0.120	0.170	0.557	0.435
11	EMF Interest Decrement cents/kWh, if applicable	n/a	-	-	-	-	-
12	Net Proposed Fuel and Fuel-Related Costs Factors cents/kWh	Exh 2 Sch 1 pg 2	2.607	2.589	2.602	2.656	2.556

Note: The above rates do not include state regulatory fees.

I/A

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.62% and Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Exhibit 2
Schedule 1
Page 1 of 3

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/KWh)	Fuel Cost ($)
			A	C/A/10=B	C
1	Total Nuclear	Workpaper 3-4	29,713,146	0.6170	$ 183,324,690
2	Coal	Workpaper 3 - 4	11,131,286	3.1353	348,993,723
3	Gas - CT and CC	Workpaper 3 - 4	22,185,181	2.6683	591,960,856
4	Reagents & Byproducts	Workpaper 5	-		26,265,057
5	Total Fossil	Sum of Lines 2 - 4	33,316,467		967,219,636
6	Hydro	Workpaper 3	648,112		
7	Net Pumped Storage		-		
8	Total Hydro	Sum of Lines 6 - 7	648,112		
9	Utility Owned Solar Generation	Workpaper 3	279,675		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	63,957,400		1,150,544,326
11	Purchases	Workpaper 3 - 4	7,560,370		464,368,032
12	JDA Savings Shared	Workpaper 5	-		(21,960,626)
13	Total Purchases	Sum of Lines 11 - 12	7,560,370		442,407,406
14	Total Generation and Purchases	Line 10 + Line 13	71,517,770		1,592,951,732
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(7,544,324)		(161,032,005)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(1,817,527)		
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16			$ 1,431,919,727
18	Projected System MWh Sales for Fuel Factor	Workpaper 3	62,155,919		62,155,919
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 /Line 18 / 10			2.304

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.62% and Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Description		Residential	General Service Small	General Service Medium	General Service Large	Lighting	Total
1	NC Projected Billing Period MWh Sales	Workpaper 8	16,265,079	1,806,876	10,414,506	9,223,825	381,171	38,091,457
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 34,622,728
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						39,793,114
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 74,415,842
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Workpaper 13						61.00%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 45,394,250
7	Production Plant Allocation Factors	Workpaper 13	49.599%	6.156%	28.252%	15.986%	0.007%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Plant %	Line 6 * Line 7	$ 22,515,098	$ 2,794,328	$ 12,824,594	$ 7,256,923	$ 3,306	$ 45,394,250
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.138	0.155	0.123	0.079	0.001	0.119
	Summary of Total Rate by Class		cents/KWh	cents/KWh	cents/KWh	cents/KWh	cents/KWh	
10	Fuel and Fuel-Related Costs excluding Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.217	2.314	2.309	2.020	2.120	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.138	0.155	0.123	0.079	0.001	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.355	2.469	2.432	2.099	2.121	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.252	0.120	0.170	0.557	0.435	
14	EMF Interest Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	-	-	-	
15	Net Fuel and Fuel-Related Costs Factors cents/kWh	Exh 2 Sch 1 Page 3	2.607	2.589	2.602	2.656	2.556	

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 94.62% and Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Rate Class	Projected Billing Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease) cents/kwh	Current Total Fuel Rate (including renewables and EMF) E-2, Sub 1173 cents/kwh	Proposed Total Fuel Rate (including renewables and EMF) cents /kwh
		A	B	C	D	E	F	G
		Workpaper 8	Workpaper 11	Line 27 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Exhibit 1, Line 4	E + F = G
1	Residential	16,265,079	$ 1,898,488,040	$ (45,419,195)	-2.4%	(0.279)	2.886	2.607
2	Small General Service	1,806,876	249,548,540	(5,970,169)	-2.4%	(0.330)	2.919	2.589
3	Medium General Service	10,414,506	950,513,824	(22,739,976)	-2.4%	(0.218)	2.820	2.602
4	Large General Service	9,223,825	534,744,328	(12,793,158)	-2.4%	(0.139)	2.795	2.656
5	Lighting	381,171	92,439,556	(2,211,513)	-2.4%	(0.580)	3.136	2.556
6	NC Retail	38,091,457	$ 3,725,734,287	$ (89,134,011)				
	Total Proposed Composite Fuel Rate:							
7	Adjusted System Total Fuel Costs	Workpaper 8	$ 1,433,036,845					
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	74,415,842					
9	Adjusted System Other Fuel Costs	Line 7 - Line 8	$ 1,358,621,003					
10	NC Retail Allocation % - sales at generation	Workpaper 10	61.68%					
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 837,997,435					
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	45,394,250					
13	NC Retail Total Fuel Costs before 2.5% Purchase Power Test	Line 11 + Line 12	$ 883,391,685					
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16	0					
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 883,391,685					
16	NC Projected Billing Period MWh Sales	Line 6, col A	38,091,457					
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 / 10	2.319					
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.291					
19	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.000					
20	Total Proposed Composite Fuel Rate	Sum of Lines 17-19	2.610					
	Total Current Composite Fuel Rate - Docket E-2 Sub 1173:							
21	Current composite Fuel Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 17	2.242					
22	Current composite EMF Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 18	0.602					
23	Current composite EMF Interest cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 19	0.000					
24	Total Current Composite Fuel Rate	Sum of Lines 21-23	2.844					
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	(0.234)					
26	NC Projected Billing Period MWh Sales	Line 6, col A	38,091,457					
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10	$ (89,134,010)					

Notes:
Rounding differences may occur
Includes 100% ownership of all generating resources

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.62% with Normalized Test Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/KWh)		Fuel Cost ($)
			A	C/A/10=B		C
1	Total Nuclear	Workpaper 3-4	29,713,146	0.6170	$	183,324,690
2	Coal	Workpaper 15	10,963,189	3.1353		343,723,461
3	Gas - CT and CC	Workpaper 3-4	22,185,181	2.6683		591,960,856
4	Reagents & Byproducts	Workpaper 4	-			26,265,057
5	Total Fossil	Sum of Lines 2 - 4	33,148,370			961,949,374
6	Hydro	Workpaper 3	648,112			
7	Net Pumped Storage		-			
8	Total Hydro	Sum of Lines 6 - 7	648,112			
9	Utility Owned Solar Generation	Workpaper 3	279,675			
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	63,789,303			1,145,274,064
11	Purchases	Workpaper 3 - 4	7,560,370			464,368,032
12	JDA Savings Shared	Workpaper 5	-			(21,960,626)
13	Total Purchases	Sum of Lines 11 - 12	7,560,370			442,407,406
14	Total Generation and Purchases	Line 10 + Line 13	71,349,673			1,587,681,470
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(7,544,324)			(161,032,005)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(1,812,883)			
17	System Fuel Expense for Fuel Factor	Lines 14 + Line 15 + Line 16			$	1,426,649,465
18	Normalized Test Period MWh Sales for Fuel Factor	Exhibit 4	61,992,467			61,992,467
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 / Line 18 / 10				2.301

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.62% with Normalized Test Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Exhibit 2
Schedule 2
Page 2 of 3

Line No.	Description		Residential	General Service Small	General Service Medium	General Service Large	Lighting	Total
1	NC Normalized Test Period MWh Sales	Workpaper 8a	16,022,241	1,943,714	11,007,307	8,368,542	353,965	37,695,769
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 34,622,728
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						39,793,114
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 74,415,842
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Input						61.00%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 45,394,250
7	Production Plant Allocation Factors	Workpaper 13	49.599%	6.156%	28.252%	15.986%	0.007%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Plant %	Line 6 * Line 7	$ 22,515,098	$ 2,794,328	$ 12,824,594	$ 7,256,923	$ 3,306	$ 45,394,250
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.141	0.144	0.117	0.087	0.001	0.120
	Summary of Total Rate by Class		cents/KWh	cents/KWh	cents/KWh	cents/KWh	cents/KWh	
10	Fuel and Fuel-Related Costs excluding Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.211	2.350	2.328	1.999	2.079	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.141	0.144	0.117	0.087	0.001	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.352	2.494	2.445	2.086	2.080	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.252	0.120	0.170	0.557	0.435	
14	EMF Interest Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	-	-	-	
15	Net Fuel and Fuel-Related Costs Factors cents/kWh	Exh 2 Sch 2 Page 3	2.604	2.614	2.615	2.643	2.515	

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 94.62% with Normalized Test Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Rate Class	Normalized Test Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease) cents/kwh	Current Total Fuel Rate (including renewables and EMF) E-2, Sub 1173 cents/kwh	Proposed Total Fuel Rate (including renewables and EMF) cents /kwh
		A	B	C	D	E	F	G
		Workpaper 8a	Workpaper 11	Line 27 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Exhibit 1, Line 4	E + F = G
1	Residential	16,022,241	$ 1,898,488,040	$ (45,139,471)	-2.4%	(0.282)	2.886	2.604
2	Small General Service	1,943,714	249,548,540	(5,933,400)	-2.4%	(0.305)	2.919	2.614
3	Medium General Service	11,007,307	950,513,824	(22,599,927)	-2.4%	(0.205)	2.820	2.615
4	Large General Service	8,368,542	534,744,328	(12,714,368)	-2.4%	(0.152)	2.795	2.643
5	Lighting	353,965	92,439,556	(2,197,892)	-2.4%	(0.621)	3.136	2.515
6	NC Retail	37,695,769	$ 3,725,734,287	$ (88,585,058)				
	Total Proposed Composite Fuel Rate:							
7	Adjusted System Total Fuel Costs	Workpaper 8a	$ 1,427,766,584					
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	74,415,842					
9	System Other Fuel Costs	Line 7 - Line 8	$ 1,353,350,741					
10	NC Retail Allocation % - sales at generation	Workpaper 10	61.21%					
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 828,385,989					
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2	45,394,250					
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 873,780,239					
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16a	0					
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 873,780,239					
16	Adjusted NC Normalized Test Period MWh Sales	Line 6, col A	37,695,769					
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 /10	2.318					
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.291					
19	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.000					
20	Total Proposed Composite Fuel Rate	Sum of Lines 17-19	2.609					
	Total Current Composite Fuel Rate - Docket E-2 Sub 1173:							
21	Current composite Fuel Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 17	2.242					
22	Current composite EMF Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 18	0.602					
23	Current composite EMF Interest cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 19	0.000					
24	Total Current Composite Fuel Rate	Sum of Lines 21 - 23	2.844					
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	(0.235)					
26	Adjusted NC Normalized Test Period MWh Sales	Line 6, col A	37,695,769					
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10	$ (88,585,058)					

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
NERC Capacity Factor of 91.8% with Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Exhibit 2
Schedule 3

Line No.	Unit	Reference	Generation (MWh)	Unit Cost (cents/KWh)	Fuel Cost ($)
			A	C/A/10=B	C
1	Total Nuclear	Workpaper 2	28,826,864	0.6170	$ 177,856,495
2	Coal	Workpaper 15	12,017,568	3.1353	376,780,866
3	Gas - CT and CC	Workpaper 3 - 4	22,185,181	2.6683	591,960,856
4	Reagents & Byproducts	Workpaper 5	-		26,265,057
5	Total Fossil	Sum of Lines 2 - 4	34,202,749		995,006,779
6	Hydro	Workpaper 3	648,112		
7	Net Pumped Storage		-		
8	Total Hydro	Sum of Lines 6 - 7	648,112		
9	Utility Owned Solar Generation	Workpaper 3	279,675		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	63,957,400		1,172,863,274
11	Purchases	Workpaper 3 - 4	7,560,370		464,368,032
12	JDA Savings Shared	Workpaper 5	-		(21,960,626)
13	Total Purchases	Sum of Lines 11 - 12	7,560,370		442,407,406
14	Total Generation and Purchases	Line 10 + Line 13	71,517,770		1,615,270,680
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(7,544,324)		(161,032,005)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(1,817,527)		
17	System Fuel Expense for Fuel Factor	Line 14 + Line 15 + Line 16			$ 1,454,238,675
18	System MWh Sales for Fuel Factor	Workpaper 3	62,155,919		62,155,919
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 / Line 18 / 10			2.340

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel-Related Cost Factors Using:
NERC Capacity Factor of 91.8% with Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Description		Residential	General Service Small	General Service Medium	General Service Large	Lighting	Total
1	NC Projected Billing Period MWh Sales	Workpaper 8	16,265,079	1,806,876	10,414,506	9,223,825	381,171	38,091,457
Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class								Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 34,622,728
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						39,793,114
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 74,415,842
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Input						61.00%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 45,394,250
7	Production Plant Allocation Factors	Workpaper 13	49.599%	6.156%	28.252%	15.986%	0.007%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Plant %	Line 6 * Line 7	$ 22,515,098	$ 2,794,328	$ 12,824,594	$ 7,256,923	$ 3,306	$ 45,394,250
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.138	0.155	0.123	0.079	0.001	0.119
Summary of Total Rate by Class			cents/KWh	cents/KWh	cents/KWh	cents/KWh	cents/KWh	
10	Fuel and Fuel-Related Costs excluding Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.260	2.364	2.342	2.042	2.209	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.138	0.155	0.123	0.079	0.001	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.398	2.519	2.465	2.121	2.210	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.252	0.120	0.170	0.557	0.435	
14	EMF Interest Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	-	-	-	
15	Net Fuel and Fuel-Related Costs Factors cents/kWh	Exh 2 Sch 3 Page 3	2.650	2.639	2.635	2.678	2.645	

Note: Rounding differences may occur

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
NERC Capacity Factor of 91.8% with Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Rate Class	Projected Billing Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease) cents/kwh	Current Total Fuel Rate (including renewables and EMF) E-2, Sub 1173 cents/kwh	Proposed Total Fuel Rate (including renewables and EMF) cents /kwh
		A	B	C	D	E	F	G
		Workpaper 8	Workpaper 11	Line 27 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Exhibit 1, Line 4	E + F = H
1	Residential	16,265,079	$ 1,898,488,040	$ (38,431,626)	-2.0%	(0.236)	2.886	2.650
2	Small General Service	1,806,876	249,548,540	(5,051,681)	-2.0%	(0.280)	2.919	2.639
3	Medium General Service	10,414,506	950,513,824	(19,241,518)	-2.0%	(0.185)	2.820	2.635
4	Large General Service	9,223,825	534,744,328	(10,824,980)	-2.0%	(0.117)	2.795	2.678
5	Lighting	381,171	92,439,556	(1,871,280)	-2.0%	(0.491)	3.136	2.645
6	NC Retail	38,091,457	$ 3,725,734,287	$ (75,421,085)				

Line No.	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
7	Adjusted System Total Fuel Costs	Workpaper 8b	$ 1,455,355,794
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	74,415,842
9	System Other Fuel Costs	Line 7 - Line 8	$ 1,380,939,952
10	NC Retail Allocation % - sales at generation	Workpaper 10	61.68%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 851,763,762
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	45,394,250
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 897,158,012
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16	0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 897,158,012
16	NC Projected Billing Period MWh Sales	Line 6, col A	38,091,457
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 /10	2.355
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.291
19	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.000
20	Total Proposed Composite Fuel Rate	Sum of Lines 15-17	2.646
	Total Current Composite Fuel Rate - Docket E-2 Sub 1173:		
21	Current composite Fuel Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 17	2.242
22	Current composite EMF Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 18	0.602
23	Current composite EMF Interest cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 19	0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21 - 23	2.844
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	(0.198)
26	NC Projected Billing Period MWh Sales	Line 6, col A	38,091,457
27	Increase/(Decrease) in Fuel Costs	Line 25* Line 26 * 10	$ (75,421,085)

Note: Rounding differences may occur

I/A

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Proposed Composite
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	#REF!	#REF!	2,821,410	$ 6,616,553	-	$ 6,616,553
2	May	#REF!	#REF!	2,743,729	13,930,507	-	13,930,507
3	June	#REF!	#REF!	3,379,527	20,501,107	-	20,501,107
4	July	#REF!	#REF!	3,687,027	13,504,786	-	13,504,786
5	August	#REF!	#REF!	3,705,569	12,651,306	-	12,651,306
6	September	#REF!	#REF!	3,324,420	22,555,310	-	22,555,310
7	October	#REF!	#REF!	3,247,434	(4,537,212)	-	(4,537,212)
8	November	#REF!	#REF!	2,905,623	14,008,619	-	14,008,619
9	December (New Rates - Sub 1173)	#REF!	#REF!	2,853,152	56,124,620	-	56,124,620
10	January 2019	#REF!	#REF!	3,344,813	19,890,481	$ (33,252)	19,857,229
11	February	#REF!	#REF!	3,239,879	(41,422,510)	-	(41,422,510)
12	March	#REF!	#REF!	2,793,993	13,007,082	-	13,007,082
13	Total Test Period			38,046,575	$ 146,830,650	$ (33,252)	$ 146,797,398
14	Booked (Over) / Under Recovery						$ 146,797,398
15	Coal Inventory Rider (Over) / Under Recovery						257,250
16	Adjustment to remove by-product net gain/loss accrued expense						(44,144,639)
17	Adjustment to include by-product net gain/loss cash payments						6,640,945
18	Total (Over) / Under Recovery						$ 109,550,954
19	Normalized Test Period MWh Sales	Exhibit 4					37,695,769
20	Experience Modification Increment / (Decrement) cents/KWh						0.291

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Residential
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.501	2.179	1,138,012	$ 3,660,529		$ 3,660,529
2	May	3.023	2.179	1,016,135	8,577,706		8,577,706
3	June	2.787	2.179	1,404,775	8,539,907		8,539,907
4	July	2.467	2.179	1,586,631	4,574,733		4,574,733
5	August	2.510	2.179	1,553,969	5,138,198		5,138,198
6	September	2.811	2.179	1,404,365	8,874,465		8,874,465
7	October	2.193	2.179	1,264,650	179,201		179,201
8	November	2.995	2.179	1,072,132	8,748,809		8,748,809
9	December (New Rates - Sub 1173)	3.604	2.237	1,386,673	18,956,228		18,956,228
10	January 2019	2.682	2.311	1,552,025	5,751,516	$ (14,440)	5,737,076
11	February	0.899	2.311	1,553,478	(21,931,387)		(21,931,387)
12	March	2.733	2.311	1,214,159	5,128,001		5,128,001
13	Total Test Period			16,147,005	$ 56,197,905	$ (14,440)	$ 56,183,465
14	Booked (Over) / Under Recovery						$ 56,183,465
15	Coal inventory Rider (Over) / Under Recovery						109,177
16	Adjustment to remove by-product net gain/loss accrued expense						(18,735,029)
17	Adjustment to include by-product net gain/loss cash payments						2,818,424
18	Total (Over) / Under Recovery						$ 40,376,037
19	Normalized Test Period MWh Sales	Exhibit 4					16,022,241
20	Experience Modification Increment (Decrement) cents/KWh						0.252

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Small General Service
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.289	2.121	140,607	$ 236,079		$ 236,079
2	May	2.535	2.121	136,871	567,097		567,097
3	June	2.480	2.121	178,846	642,201		642,201
4	July	2.281	2.121	194,597	310,810		310,810
5	August	2.231	2.121	198,191	217,119		217,119
6	September	2.489	2.121	179,772	662,100		662,100
7	October	1.789	2.121	174,119	(578,233)		(578,233)
8	November	2.312	2.121	156,234	298,658		298,658
9	December (New Rates - Sub 1173)	4.862	2.313	120,842	3,080,272		3,080,272
10	January 2019	2.969	2.556	174,110	718,822	$ (1,763)	717,059
11	February	1.095	2.556	159,655	(2,332,952)		(2,332,952)
12	March	2.847	2.556	144,886	421,865		421,865
13	Total Test Period			1,958,731	$ 4,243,838	$ (1,763)	$ 4,242,075
14	Booked (Over) / Under Recovery						$ 4,242,075
15	Coal inventory Rider (Over) / Under Recovery						13,244
16	Adjustment to remove by-product net gain/loss accrued expense						(2,272,674)
17	Adjustment to include by-product net gain/loss cash payments						341,892
18	Total (Over) / Under Recovery						$ 2,324,536
19	Normalized Test Period MWh Sales	Exhibit 4					1,943,714
20	Experience Modification Increment (Decrement) cents/KWh						0.120

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Medium General Service
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.440	2.356	834,634	$ 700,759		$ 700,759
2	May	2.524	2.356	871,652	1,468,210		1,468,210
3	June	2.683	2.356	1,042,496	3,411,985		3,411,985
4	July	2.601	2.356	1,074,969	2,629,373		2,629,373
5	August	2.536	2.356	1,098,143	1,980,830		1,980,830
6	September	2.852	2.356	988,512	4,902,428		4,902,428
7	October	1.955	2.356	1,021,065	(4,091,099)		(4,091,099)
8	November	2.453	2.356	940,892	913,230		913,230
9	December (New Rates - Sub 1173)	5.035	2.409	706,334	18,544,231		18,544,231
10	January 2019	3.287	2.477	883,889	7,155,890	$ (9,828)	7,146,062
11	February	1.127	2.477	855,202	(11,548,986)		(11,548,986)
12	March	2.927	2.477	790,364	3,557,351		3,557,351
13	Total Test Period			11,108,152	$ 29,624,202	$ (9,828)	$ 29,614,374
14	Booked (Over) / Under Recovery						$ 29,614,374
15	Coal Inventory Rider (Over) / Under Recovery						75,107
16	Adjustment to remove by-product net gain/loss accrued expense						(12,888,554)
17	Adjustment to include by-product net gain/loss cash payments						1,938,903
18	Total (Over) / Under Recovery						$ 18,739,830
19	Normalized Test Period MWh Sales	Exhibit 4					11,007,307
20	Experience Modification Increment (Decrement) cents/KWh						0.170

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Large General Service
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.709	2.417	678,418	$ 1,978,810		$ 1,978,810
2	May	2.886	2.417	689,394	3,230,432		3,230,432
3	June	3.476	2.417	723,936	7,668,586		7,668,586
4	July	3.135	2.417	801,315	5,754,642		5,754,642
5	August	3.034	2.417	825,198	5,091,306		5,091,306
6	September	3.504	2.417	723,070	7,861,222		7,861,222
7	October	2.406	2.417	757,387	(84,221)		(84,221)
8	November	2.971	2.417	707,153	3,914,585		3,914,585
9	December (New Rates - Sub 1173)	4.582	2.125	610,753	15,002,143		15,002,143
10	January 2019	2.603	1.757	704,241	5,960,860	$ (7,072)	5,953,788
11	February	0.937	1.757	643,138	(5,275,468)		(5,275,468)
12	March	2.371	1.757	615,274	3,776,307		3,776,307
13	Total Test Period			8,479,278	$ 54,879,204	$ (7,072)	$ 54,872,132
14	Booked (Over) / Under Recovery						$ 54,872,132
15	Coal Inventory Rider (Over) / Under Recovery						57,332
16	Adjustment to remove by-product net gain/loss accrued expense						(9,838,327)
17	Adjustment to include by-product net gain/loss cash payments						1,480,039
18	Total (Over) / Under Recovery						$ 46,571,176
19	Normalized Test Period MWh Sales	Exhibit 4					8,368,542
20	Experience Modification Increment (Decrement) cents/KWh						0.557

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Lighting
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	1.793	1.657	29,739	$ 40,376		$ 40,376
2	May	1.950	1.657	29,677	87,063		87,063
3	June	2.466	1.657	29,473	238,428		238,428
4	July	2.454	1.657	29,516	235,228		235,228
5	August	2.401	1.657	30,068	223,853		223,853
6	September	2.546	1.657	28,700	255,094		255,094
7	October	1.780	1.657	30,213	37,141		37,141
8	November	2.113	1.657	29,213	133,338		133,338
9	December (New Rates - Sub 1173)	3.817	1.919	28,549	541,747		541,747
10	January 2019	3.244	2.251	30,547	303,393	$ (149)	303,244
11	February	1.076	2.251	28,406	(333,718)		(333,718)
12	March	2.673	2.251	29,310	123,557		123,557
13	Total Test Period			353,410	$ 1,885,501	$ (149)	$ 1,885,352
14	Booked (Over) / Under Recovery						$ 1,885,352
15	Coal inventory Rider (Over) / Under Recovery						2,390
16	Adjustment to remove by-product net gain/loss accrued expense						(410,055)
17	Adjustment to include by-product net gain/loss cash payments						61,687
18	Total (Over) / Under Recovery						$ 1,539,374
19	Normalized Test Period MWh Sales	Exhibit 4					353,965
20	Experience Modification Increment (Decrement) cents/KWh						0.435

Notes:
Totals may not foot due to rounding.

I/A

Harrington Exhibit 4

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Normalized Test Period MWh Sales, Fuel and Fuel-Related Revenue, Fuel and Fuel-Related Expense, and System Peak
Test Period Twelve Months Ended March 31, 2019
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Description	Reference	Total Company	North Carolina Retail	North Carolina Residential	North Carolina Small General Service	North Carolina Medium General Service	North Carolina Large General Service	North Carolina Lighting
1	Test Period MWh Sales	Workpaper 8a	62,568,164	38,046,575	16,147,005	1,958,731	11,108,152	8,479,278	353,410
2	Customer Growth MWh Adjustment	Workpaper 8a	295,033	161,504	120,250	5,244	35,216	238	555
3	Weather MWh Adjustment	Workpaper 8a	(870,731)	(512,310)	(245,014)	(20,261)	(136,061)	(110,973)	-
4	Total Adjusted MWh Sales	Sum Lines 1-3	61,992,467	37,695,769	16,022,241	1,943,714	11,007,307	8,368,542	353,965
5	Test Period Fuel and Fuel-Related Revenue *		$ 1,420,894,881	$ 864,024,095					
6	Test Period Fuel and Fuel-Related Expense *		$ 1,670,130,626	$ 1,010,821,493					
7	Test Period Unadjusted (Over)/Under Recovery	Line 5 - Line 6	$ 249,235,745	$ 146,797,398					

Line No.	Description	2018 Winter Coincidental Peak (CP) KW
8	Total System Peak	15,022,364
9	NC Retail	8,952,091
10	NC Residential Peak	5,755,959
11	NC Small General Service	536,770
12	NC Medium General Service	1,812,628
13	NC Large General Service	846,735

Notes:
* Total Company Fuel and Fuel-Related Revenue and Fuel and Fuel-Related Expense are quantifed based on NC Retail's known share of revenues and expenses grossed up to also include the percentage of sales not belonging to NC Retail.

Rounding differences may occur.

I/A

Harrington Exhibit 5

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Nuclear Capacity Ratings - MWs
Test Period Twelve Months Ended March 31, 2019
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Unit	Rate Case Docket E-2, Sub 1142	Fuel Docket E-2, Sub 1173	Proposed Capacity Rating MW
Brunswick 1	938	938	938
Brunswick 2	932	932	932
Harris 1	928	932	964
Robinson 2	741	741	741
Total Company	3,539	3,543	3,575

I/A

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Monthly Fuel and Baseload Report for March 2019
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Harrington Exhibit 6

March 2019
Monthly Fuel Filing and Baseload Report Cover Sheet

Schedule 1

Duke Energy Progress
Summary of Monthly Fuel Report

Docket No. E-2, Sub 1201

Line No.	Fuel Expenses:		March 2019		12 Months Ended March 2019
1	Total Fuel and Fuel-Related Costs	$	123,073,670	$	1,663,002,005
	MWH sales:				
2	Total System Sales		4,925,855		68,235,058
3	Less intersystem sales		372,873		5,666,892
4	Total sales less intersystem sales		4,552,982		62,568,166
5	Total fuel and fuel-related costs (¢/KWH) (Line 1/Line 4)		2.703		2.658
6	Current fuel & fuel-related cost component (¢/KWH) (per Schedule 4, Line 5a Total)		2.248		
	Generation Mix (MWH):				
	Fossil (By Primary Fuel Type):				
7	Coal		644,674		8,081,365
8	Oil		4,565		77,366
9	Natural Gas - Combustion Turbine		121,930		4,022,746
10	Natural Gas - Combined Cycle		1,611,916		19,134,953
11	Biogas		692		4,404
12	Total Fossil		2,383,777		31,320,834
13	Nuclear		1,979,009		27,748,149
14	Hydro - Conventional		82,564		848,406
15	Solar Distributed Generation		19,304		227,472
16	Total MWH generation		4,464,654		60,144,861

Notes: Detail amounts may not add to totals shown due to rounding.

Schedule 2

Duke Energy Progress
Details of Fuel and Fuel-Related Costs

Docket No. E-2, Sub 1201

Description	March 2019	12 Months Ended March 2019
Fuel and Fuel-Related Costs:		
Steam Generation - Account 501		
0501110 coal consumed - steam	$ 24,936,974	$ 303,392,775
0501310 fuel oil consumed - steam	772,460	10,958,684
Total Steam Generation - Account 501	25,709,434	314,351,459
Nuclear Generation - Account 518		
0518100 burnup of owned fuel	12,427,031	181,956,774
Other Generation - Account 547		
0547000 natural gas consumed - Combustion Turbine	12,289,318	168,066,557
0547000 natural gas consumed - Combined Cycle	42,551,124	570,332,536
0547106 biogas consumed - Combined Cycle	43,261	247,299
0547200 fuel oil consumed	97,672	6,051,638
Total Other Generation - Account 547	54,981,375	744,698,030
Reagents		
Catalyst Depreciation	131,225	1,569,962
Reagents (lime, limestone, ammonia, urea, dibasic acid, and sorbents)	1,306,098	17,186,374
Total Reagents	1,437,323	18,756,335
By-products		
Net proceeds from sale of by-products	1,611,921	86,567,009
Total By-products	1,611,921	86,567,009
Total Fossil and Nuclear Fuel Expenses Included in Base Fuel Component	96,167,083	1,346,329,607
Purchased Power and Net Interchange - Account 555		
Capacity component of purchased power (PURPA)	1,865,608	28,376,807
Capacity component of purchased power (renewables)	2,480,350	42,762,017
Fuel and fuel-related component of purchased power	32,070,833	485,950,079
Total Purchased Power and Net Interchange - Account 555	36,416,791	557,088,903
Less:		
Fuel and fuel-related costs recovered through intersystem sales	9,510,359	240,413,239
Solar Integration Charge	(154)	3,267
Total Fuel Credits - Accounts 447/456	9,510,205	240,416,505
Total Fuel and Fuel-Related Costs	$ 123,073,670	$ 1,663,002,005

Notes: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY PROGRESS
PURCHASED POWER AND INTERCHANGE
SYSTEM REPORT - NORTH CAROLINA VIEW

MARCH 2019

Schedule 3, Purchases

Purchased Power	Total	Capacity	Non-capacity			
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel $ Not Fuel-related $
Broad River Energy, LLC.	$ 2,802,106	$ 1,102,735	28,420	$ 1,238,034	$ 461,337	
City of Fayetteville	740,091	707,850	146	19,791	12,450	
DE Carolinas - Native Load Transfer	6,202,943	-	189,488	5,081,031	1,120,681	$ 1,231
DE Carolinas - Native Load Transfer Benefit	1,129,259	-	-	1,129,259	-	
DE Carolinas - Fees	501,604	-	-	-	501,604	
Haywood EMC	28,300	28,300	-	-	-	
NCEMC	3,471,917	2,777,986	16,181	693,931	-	
PJM Interconnection, LLC.	4,103		115	2,350	1,753	
Southern Company Services	4,236,908	802,620	107,883	2,828,970	605,318	
	$ 19,117,231	$ 5,419,491	342,233	$ 10,993,366	$ 2,703,143	$ 1,231
Renewable Energy						
REPS	$ 12,798,250	-	189,866	$ -	$ 12,798,250	-
DERP Qualifying Facilities	30,356	-	620	-	30,356	-
	$ 12,828,606	$ -	190,486	$ -	$ 12,828,606	$ -
HB589 PURPA Purchases						
Qualifying Facilities	$ 9,737,521	-	164,313		$ 9,737,521	-
	$ 9,737,521	$ -	164,313	$ -	$ 9,737,521	$ -
Non-dispatchable						
DE Carolinas - Reliability	$ 233,640	-	4,248	$ 142,520		$ 91,120
Energy Imbalance	12,053		372	10,929		1,124
Generation Imbalance	788		31	706		82
	$ 246,481	$ -	4,651	$ 154,155	$ -	$ 92,326
Total Purchased Power	$ 41,929,839	$ 5,419,491	701,683	$ 11,147,521	$ 25,269,270	$ 93,557

NOTES: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY PROGRESS
INTERSYSTEM SALES*
SYSTEM REPORT - NORTH CAROLINA VIEW

MARCH 2019

Schedule 3, Sales

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:					
SC Electric & Gas - Emergency	$ 4,224	-	107	$ 4,009	$ 215
Market Based:					
NCEMC Purchase Power Agreement	1,027,466	652,500	10,969	298,841	76,125
PJM Interconnection, LLC.	18,622	-	485	14,681	3,941
Other:					
DE Carolinas - Native Load Transfer Benefit	1,181,175	-	-	1,181,175	-
DE Carolinas - Native Load Transfer	8,263,589	-	361,305	8,011,653	251,936
Generation Imbalance	(3)	-	7	-	(3)
Total Intersystem Sales	$ 10,495,073	$ 652,500	372,873	$ 9,510,359	$ 332,214

* Sales for resale other than native load priority.

NOTE: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY PROGRESS
PURCHASED POWER AND INTERCHANGE
SYSTEM REPORT - NORTH CAROLINA VIEW

Twelve Months Ended MARCH 2019

Schedule 3, Purchases

Purchased Power	Total	Capacity	Non-capacity			
						Not Fuel $
Economic	$	$	mWh	Fuel $	Fuel-related $	Not Fuel-related $
Broad River Energy, LLC.	$ 127,085,389	$ 46,074,078	1,857,244	$ 68,440,822	$ 12,570,489	
City of Fayetteville	14,767,157	12,593,900	30,153	1,680,747	492,510	
DE Carolinas - Native Load Transfer	63,545,930	-	1,982,523	30,527,552	33,022,675	$ (4,297)
DE Carolinas - Native Load Transfer Benefit	5,755,905	-	-	5,755,905	-	
DE Carolinas - Fees	773,278	-	-	-	773,278	
Haywood EMC	346,350	346,350	-	-	-	
NCEMC	57,008,844	37,312,025	474,860	19,696,819	-	
PJM Interconnection, LLC.	3,551,137	-	117,614	2,113,417	1,437,720	
Southern Company Services	52,566,483	13,555,154	1,139,356	32,594,041	6,417,288	
	$ 325,400,473	$ 109,881,507	5,601,750	$ 160,809,303	$ 54,713,960	$ (4,297)
Renewable Energy						
REPS	$ 211,302,302	-	3,077,611	-	$ 211,302,302	-
DERP Net Metering Excess Generation	3,230	$ 557	75	-	-	$ 2,673
DERP Qualifying Facilities	568,966	-	11,630	-	568,966	-
	$ 211,874,498	$ 557	3,089,316	$ -	$ 211,871,268	$ 2,673
HB589 PURPA Purchases						
Qualifying Facilities	$ 126,885,293	$ -	2,036,984		$ 126,885,293	$ -
	$ 126,885,293	$ -	2,036,984	$ -	$ 126,885,293	$ -
Non-dispatchable						
DE Carolinas - Emergency	$ 15,390	-	333	$ 13,113		$ 2,277
DE Carolinas - Reliability	3,464,748	-	52,921	2,113,496		1,351,252
Haywood EMC	5,388	$ 5,388	-	-		-
Energy Imbalance	696,075	-	17,801	660,759		35,316
Generation Imbalance	35,222	-	1,462	21,711		13,511
	$ 4,216,823	$ 5,388	72,517	$ 2,809,079	$ -	$ 1,402,356
Total Purchased Power	$ 668,377,087	$ 109,887,452	10,800,567	$ 163,618,382	$ 393,470,521	$ 1,400,732

NOTES: Detail amounts may not add to totals shown due to rounding.

DUKE ENERGY PROGRESS
INTERSYSTEM SALES*
SYSTEM REPORT - NORTH CAROLINA VIEW

Twelve Months Ended
MARCH 2019

Schedule 3, Sales

Sales	Total $	Capacity $	Non-capacity mWh	Non-capacity Fuel $	Non-capacity Non-fuel $
Utilities:					
SC Electric & Gas - Emergency	$ 16,314	-	312	$ 14,320	$ 1,994
SC Public Service Authority - Emergency	103	-	-	-	103
Market Based:					
NCEMC Purchase Power Agreement	11,778,585	$ 7,830,000	107,498	3,931,062	17,523
PJM Interconnection, LLC.	87,823	-	3,945	93,554	(5,731)
Other:					
DE Carolinas - Native Load Transfer Benefit	17,548,845	-	-	17,548,845	-
DE Carolinas - Native Load Transfer	177,756,508	-	5,554,827	168,972,668	8,783,840
DE Carolinas - Native Load Transfer (Prior Period Adjust.)	51,500,000	-	-	49,852,000	1,648,000
Generation Imbalance	2,394	-	310	790	1,604
Total Intersystem Sales	$ 258,690,572	$ 7,830,000	5,666,892	$ 240,413,239	$ 10,447,333

* Sales for resale other than native load priority.

NOTES: Detail amounts may not add to totals shown due to rounding.

Schedule 4

Duke Energy Progress
(Over) / Under Recovery of Fuel Costs
March 2019

Line No.			Residential	Small General Service	Medium General Service	Large General Service	Lighting	Total
1	1a. System Retail kWh sales	Input						4,552,981,616
	1b. System kWh Sales at generation	Input						4,696,445,723
2	2a. DERP Net Metered kWh generation	Input						2,501,687
	2b. Line loss percentage from Cost of Service	Input Annually						3.460%
	2c. DERP Net Metered kWh at generation	L2a * (1 + 2b)						2,588,246
3	Adjusted System kWh sales	L1b + L2c						4,699,033,968
4	4a. N.C. Retail kWh sales	Input	1,214,159,107	144,888,112	790,364,355	616,274,288	29,309,559	2,793,993,421
	4b. Line loss percentage from Cost of Service	Input Annually	3.787%	3.788%	3.685%	3.080%	3.785%	
	4c. NC kWh Sales at generation	4a * (1+4b)	1,260,139,312	150,371,500	819,489,281	634,224,736	30,418,926	2,894,643,755
	4d. NC allocation % by customer class	Calculated	43.533%	5.195%	28.311%	21.910%	1.051%	
	4e. NC retail % of actual system total	L4c NC Total / L1b Total System						61.635%
	4f. NC retail % of adjusted system total	L4c NC Total / L3 Total System						61.601%
5	Approved fuel and fuel-related rates (¢/kWh)							
	5a Billed rates by class (¢/kWh)	Input Annually	2.311	2.556	2.477	1.757	2.251	2.248
	5b Billed fuel expense	L4a * L5a / 100	$28,059,217	$3,703,289	$19,577,325	$10,810,369	$659,758	$62,809,958
6	Incurred base fuel and fuel-related (less renewable purchased power capacity) rates by class (¢/kWh)							
	Allocation changes:							
	6a New approved Docket E-2, Sub 1173 allocation factor	Input Annually	43.60%	5.40%	30.57%	19.36%	1.07%	100.00%
	6b System Incurred expense	Input						$118,807,916
	6c NC Incurred expense by class	L4f * L6a * L6b	$31,909,473	$3,952,091	$22,373,224	$14,168,977	$783,099	$73,186,865
	6d NC Incurred base fuel rates (¢/kWh)	L6c / L4a * 100	2.62811	2.72772	2.83075	2.30287	2.67182	2.61944
7	Incurred renewable purchased power capacity rates (¢/kWh)							
	7a NC retail production plant %	Input Annually						60.52%
	7b Production plant allocation factors	Input Annually	48.581%	6.580%	28.950%	15.881%	0.008%	100.00%
	7c System Incurred expense	Input						$4,345,958
	7d NC Incurred renewable capacity expense	L7a * L7b * L7c	$1,277,786	$173,060	$761,440	$417,697	$216	$2,630,204
	7e NC incurred rates by class	L7d / L4a * 100	0.10524	0.11945	0.09634	0.06789	0.00074	0.09414
8	Total incurred rates by class (¢/kWh)	L6h + 7e	2.7334	2.8472	2.9271	2.3708	2.6726	
9	Difference in ¢/kWh (incurred - billed)	L8 - L5a	0.42235	0.29117	0.45009	0.61378	0.42156	
10	(Over) / under recovery [See footnote]	L9 * L4a / 100	$5,128,001	$421,865	$3,557,351	$3,776,307	$123,557	$13,007,081
11	Prior period adjustments	Input						
12	Total (over) / under recovery [See footnote]	L10 + L11	$5,128,001	$421,865	$3,557,351	$3,776,307	$123,557	$13,007,081
13	Total System Incurred Expenses							$123,153,874
14	Less: Jurisdictional allocation adjustment	Input						80,204
15	Total Fuel and Fuel-related Costs per Schedule 2							$123,073,671
16	(Over) / under recovery for each month of the current test period [See footnote]							

		(Over) / Under Recovery						
		Total To Date	Residential	Small General Service	Medium General Service	Large General Service	Lighting	Total Company
	April 2018	$ 6,816,553	3,660,529	236,079	700,759	1,978,810	40,376	$ 6,816,553
	May	20,547,061	8,577,706	567,097	1,468,210	3,230,432	87,063	13,930,508
	June	41,048,168	8,539,907	642,201	3,411,985	7,668,586	238,428	20,501,107
	July	54,552,954	4,574,733	310,810	2,629,373	5,754,642	235,228	13,504,786
	August	67,204,260	5,138,198	217,119	1,980,630	5,091,306	223,853	12,651,306
	September	89,759,569	8,874,465	662,100	4,902,428	7,861,222	256,094	22,555,309
	October	85,222,358	179,201	(578,233)	(4,091,099)	(84,221)	37,141	(4,537,211)
	November	99,230,978	8,748,809	296,658	913,230	3,914,585	133,338	14,008,620
	December	155,355,599	18,956,228	3,080,272	18,544,231	15,002,143	541,747	56,124,621
_/1	January 2019	175,212,828	5,737,076	717,059	7,148,062	5,953,788	303,244	19,857,229
	February	133,790,317	(21,931,387)	(2,332,952)	(11,546,986)	(5,275,468)	(333,716)	(41,422,511)
	March	146,797,398	5,128,001	421,865	3,557,351	3,776,307	123,557	13,007,081
	Total		$ 56,183,466	$ 4,242,075	$ 29,614,374	$ 54,872,132	$ 1,885,351	$ 146,797,398

Notes:

Detail amounts may not recalculate due to percentages presented as rounded.

Presentation of over or under collected amounts reflects a regulatory asset or liability. Over collections, or regulatory liabilities, are shown as negative amounts. Under collections, or regulatory assets, are shown as positive amounts.

_/1 Includes prior period adjustments.

Duke Energy Progress
Fuel and Fuel Related Cost Report
March 2019

Description	Weatherspoon CT	Lee CC	Sutton CC/CT	Robinson Nuclear	Asheville Steam	Asheville CT	Roxboro Steam	Mayo Steam
Cost of Fuel Purchased ($)								
Coal	-	-	-	-	$5,221,006	-	$20,932,462	$8,482,923
Oil	108,542	-	-	-	(99)	-	451,673	404,633
Gas - CC	-	20,510,566	13,595,268	-	-	-	-	-
Gas - CT	24	-	653,299	-	-	2,150,497	-	-
Biogas	-	-	-	-	-	-	-	-
Total	108,566	$20,510,566	$14,248,567	-	$5,220,907	$2,150,497	$21,384,135	$8,887,556
Average Cost of Fuel Purchased (¢/MBTU)								
Coal	-	-	-	-	364.47	-	330.49	280.74
Oil	1,465.69	-	-	-	1,414.29	-	1,499.83	1,499.20
Gas - CC	-	405.30	470.88	-	-	-	-	-
Gas - CT	-	-	463.78	-	-	4,363.74	-	-
Biogas	-	-	-	-	-	-	-	-
Weighted Average	1,496.02	405.30	470.54	-	364.46	4,363.74	336.02	291.52
Cost of Fuel Burned ($)								
Coal	-	-	-	-	$5,236,744	-	$17,321,167	$2,379,063
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	23,727	-	-	-	96,120	22,056	520,592	155,747
Gas - CC	-	20,510,566	13,595,268	-	-	-	-	-
Gas - CT	24	-	653,299	-	-	2,150,497	-	-
Biogas	-	-	-	-	-	-	-	-
Nuclear	-	-	-	3,301,699	-	-	-	-
Total	$23,751	$20,510,566	$14,248,567	$3,301,699	$5,332,864	$2,172,553	$17,841,759	$2,534,810
Average Cost of Fuel Burned (¢/MBTU)								
Coal	-	-	-	-	337.22	-	352.43	318.76
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	1,590.28	-	-	-	1,538.17	1,538.08	1,521.44	1,531.44
Gas - CC	-	405.30	470.88	-	-	-	-	-
Gas - CT	-	-	463.78	-	-	4,363.74	-	-
Biogas	-	-	-	-	-	-	-	-
Nuclear	-	-	-	55.67	-	-	-	-
Weighted Average	1,591.89	405.30	470.54	55.67	342.03	4,283.85	360.52	335.06
Average Cost of Generation (¢/kWh)								
Coal	-	-	-	-	4.12	-	3.83	3.65
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	-	-	-	-	18.82	25.35	16.38	17.53
Gas - CC	-	2.89	3.33	-	-	-	-	-
Gas - CT	-	-	4.70	-	-	68.59	-	-
Biogas	-	-	-	-	-	-	-	-
Nuclear	-	-	-	0.56	-	-	-	-
Weighted Average	-	2.89	3.38	0.56	4.18	67.43	3.92	3.84
Burned MBTU's								
Coal	-	-	-	-	1,552,934	-	4,914,738	746,358
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	1,492	-	-	-	6,249	1,434	34,217	10,170
Gas - CC	-	5,060,592	2,887,234	-	-	-	-	-
Gas - CT	-	-	140,865	-	-	49,281	-	-
Biogas	-	-	-	-	-	-	-	-
Nuclear	-	-	-	5,930,593	-	-	-	-
Total	1,492	5,060,592	3,028,099	5,930,593	1,559,183	50,715	4,948,955	756,528
Net Generation (mWh)								
Coal	-	-	-	-	127,212	-	452,280	65,182
Oil - CC	-	-	-	-	-	-	-	-
Oil - Steam/CT	(28)	-	-	-	511	87	3,179	888
Gas - CC	-	710,152	408,268	-	-	-	-	-
Gas - CT	-	-	13,900	-	-	3,135	-	-
Biogas	-	-	-	-	-	-	-	-
Nuclear	-	-	-	587,358	-	-	-	-
Hydro (Total System)								
Solar (Total System)								
Total	(28)	710,152	422,168	587,358	127,723	3,222	455,459	66,070
Cost of Reagents Consumed ($)								
Ammonia	-	-	-	-	-	-	$75,257	$9,558
Limestone	-	-	-	-	164,560	-	574,657	99,999
Re-emission Chemical	-	-	-	-	-	-	-	-
Sorbents	-	-	-	-	5,765	-	216,421	32,145
Urea	-	-	-	-	114,710	-	-	-
Total	-	-	-	-	$285,035	-	$866,336	$141,702

Notes:
Detail amounts may not add to totals shown due to rounding.
Schedule excludes in-transit, terminal and tolling agreement activity.
Cents/MBTU and cents/kWh are not computed when costs and/or net generation is negative.
Lee and Wayne oil burn is associated with inventory consumption shown on Schedule 6 for Wayne.
Re-emission chemical reagent expense is not recoverable in NC.

Duke Energy Progress
Fuel and Fuel Related Cost Report
March 2019

Description	Brunswick Nuclear	Blewett CT	Wayne County CT	Darlington CT	Smith Energy Complex CC/CT	Harris Nuclear	Current Month	Total 12 ME March 2019
Cost of Fuel Purchased ($)								
Coal	-	-	-	-	-	-	$34,836,391	$306,305,928
Oil	2,331	-	-	-	-	-	967,080	18,118,231
Gas - CC	-	-	-	-	8,445,290	-	42,551,124	570,332,536
Gas - CT	-	-	243,212	54,046	9,188,240	-	12,289,318	168,066,557
Biogas	-	-	-	-	128,337	-	128,337	920,702
Total	2,331	-	$243,212	$54,046	$17,633,530	-	$90,572,250	$1,063,743,952
Average Cost of Fuel Purchased (¢/MBTU)								
Coal	-	-	-	-	-	-	321.07	336.61
Oil	-	-	-	-	-	-	1,502.73	1,508.31
Gas - CC	-	-	-	-	389.64	-	420.66	416.97
Gas - CT	-	-	399.99	408.17	375.47	-	453.26	368.85
Biogas	-	-	-	-	2,919.40	-	2,919.40	2,933.85
Weighted Average	-	-	399.99	408.17	384.54	-	382.43	387.41
Cost of Fuel Burned ($)								
Coal	-	-	-	-	-	-	$24,936,974	$303,392,775
Oil - CC	-	-	-	-	149	-	149	2,216
Oil - Steam/CT	-	19,661	-	14,049	18,031	-	869,983	17,008,105
Gas - CC	-	-	-	-	8,445,290	-	42,551,124	570,332,536
Gas - CT	-	-	243,212	54,046	9,188,240	-	12,289,318	168,066,557
Biogas	-	-	-	-	128,337	-	128,337	920,702
Nuclear	4,276,463	-	-	-	-	4,848,869	12,427,031	181,956,773
Total	$4,276,463	19,661	$243,212	$68,095	17,780,047.00	$4,848,869	$93,202,916	$1,241,679,664
Average Cost of Fuel Burned (¢/MBTU)								
Coal	-	-	-	-	-	-	345.67	331.03
Oil - CC	-	-	-	-	1,655.58	-	1,655.56	1,653.73
Oil - Steam/CT	-	1,683.33	-	1,730.17	1,663.38	-	1,536.37	1,583.93
Gas - CC	-	-	-	-	389.64	-	420.66	416.97
Gas - CT	-	-	399.99	408.17	375.47	-	453.26	368.85
Biogas	-	-	-	-	2,919.40	-	2,919.40	2,933.85
Nuclear	61.77	-	-	-	-	64.95	61.16	62.63
Weighted Average	61.77	1,683.33	399.99	484.56	384.84	64.95	230.58	219.53
Average Cost of Generation (¢/kWh)								
Coal	-	-	-	-	-	-	3.87	3.75
Oil - CC	-	-	-	-	14.90	-	14.90	18.47
Oil - Steam/CT	-	-	-	-	18.30	-	19.06	21.99
Gas - CC	-	-	-	-	1.71	-	2.64	2.98
Gas - CT	-	-	5.72	10.10	9.18	-	10.08	4.18
Biogas	-	-	-	-	18.53	-	18.53	20.91
Nuclear	0.65	-	-	-	-	0.66	0.63	0.66
Weighted Average	0.65	-	5.72	17.83	2.99	0.66	2.09	2.06
Burned MBTU's								
Coal	-	-	-	-	-	-	7,214,030	91,650,544
Oil - CC	-	-	-	-	9	-	9	134
Oil - Steam/CT	-	1,168	-	812	1,084	-	56,626	1,073,793
Gas - CC	-	-	-	-	2,167,471	-	10,115,297	136,760,403
Gas - CT	-	-	60,805	13,241	2,447,150	-	2,711,342	45,564,794
Biogas	-	-	-	-	4,396	-	4,396	31,382
Nuclear	6,923,119	-	-	-	-	7,465,910	20,319,622	290,513,318
Total	6,923,119	1,168	60,805	14,053	4,620,110	7,465,910	40,421,322	565,614,368
Net Generation (mWh)								
Coal	-	-	-	-	-	-	644,674	8,081,365
Oil - CC	-	-	-	-	1	-	1	12
Oil - Steam/CT	-	(18)	-	(153)	99	-	4,564	77,354
Gas - CC	-	-	-	-	493,496	-	1,611,916	19,134,953
Gas - CT	-	-	4,250	535	100,109	-	121,930	4,022,746
Biogas	-	-	-	-	692	-	692	4,404
Nuclear	653,858	-	-	-	-	737,793	1,979,009	27,748,149
Hydro (Total System)							82,564	848,406
Solar (Total System)							19,304	227,472
Total	653,858	(18)	4,250	382	594,397	737,793	4,464,854	60,144,861
Cost of Reagents Consumed ($)								
Ammonia	-	-	-	-	$13,025	-	$97,840	$1,636,851
Limestone	-	-	-	-	-	-	839,216	11,266,783
Re-emission Chemical	-	-	-	-	-	-	-	84,162
Sorbents	-	-	-	-	-	-	254,331	3,094,114
Urea	-	-	-	-	-	-	114,710	1,188,625
Total	-	-	-	-	$13,025	-	$1,306,098	$17,270,536

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
March 2019

Schedule 6

Description	Weatherspoon	Lee	Sutton	Robinson	Asheville
Coal Data:					
Beginning balance	-	-	-	-	76,420
Tons received during period	-	-	-	-	57,452
Inventory adjustments	-	-	-	-	-
Tons burned during period	-	-	-	-	62,187
Ending balance	-	-	-	-	71,685
MBTUs per ton burned	-	-	-	-	24.97
Cost of ending inventory ($/ton)	-	-	-	-	84.21
Oil Data:					
Beginning balance	642,863	-	2,623,651	78,040	2,980,615
Gallons received during period	52,588	-	-	-	(50)
Miscellaneous use and adjustments	-	-	-	-	(5,202)
Gallons burned during period	10,657	-	-	-	55,895
Ending balance	684,794	-	2,623,651	78,040	2,919,468
Cost of ending inventory ($/gal)	2.23	-	2.80	2.42	2.11
Natural Gas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	4,891,110	2,950,888	-	48,124
MCF burned during period	-	4,891,110	2,950,888	-	48,124
Ending balance	-	-	-	-	-
Biogas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	-	-	-	-
MCF burned during period	-	-	-	-	-
Ending balance	-	-	-	-	-
Limestone/Lime Data:					
Beginning balance	-	-	-	-	15,946
Tons received during period	-	-	-	-	3,770
Inventory adjustments	-	-	-	-	-
Tons consumed during period	-	-	-	-	3,046
Ending balance	-	-	-	-	16,670
Cost of ending inventory ($/ton)	-	-	-	-	51.83

Notes:
Detail amounts may not add to totals shown due to rounding.
Schedule excludes in-transit, terminal and tolling agreement activity.
Gas is burned as received; therefore, inventory balances are not maintained.
The oil inventory data for Wayne reflects the common usage of the oil tank used for both Wayne and Lee units.

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
March 2019

Schedule 6

Description	Roxboro	Mayo	Brunswick	Blewett	Wayne County
Coal Data:					
Beginning balance	918,904	233,107	-	-	-
Tons received during period	252,785	115,986	-	-	-
Inventory adjustments	-	-	-	-	-
Tons burned during period	193,871	29,161	-	-	-
Ending balance	977,818	319,932	-	-	-
MBTUs per ton burned	25.35	25.59	-	-	-
Cost of ending inventory ($/ton)	89.33	81.58	-	-	-
Oil Data:					
Beginning balance	226,564	185,849	170,137	798,782	12,012,380
Gallons received during period	218,223	195,583	-	-	-
Miscellaneous use and adjustments	(7,509)	(2,879)	-	-	-
Gallons burned during period	248,114	73,853	5,958	8,311	-
Ending balance	189,164	304,700	164,179	790,471	12,012,380
Cost of ending inventory ($/gal)	2.10	2.11	2.42	2.37	2.40
Natural Gas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	-	-	-	58,639
MCF burned during period	-	-	-	-	58,639
Ending balance	-	-	-	-	-
Biogas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	-	-	-	-
MCF burned during period	-	-	-	-	-
Ending balance	-	-	-	-	-
Limestone/Lime Data:					
Beginning balance	57,492	18,726	-	-	-
Tons received during period	6,784	46	-	-	-
Inventory adjustments	-	-	-	-	-
Tons consumed during period	13,316	1,826	-	-	-
Ending balance	50,960	16,946	-	-	-
Cost of ending inventory ($/ton)	41.10	51.77	-	-	-

Duke Energy Progress
Fuel & Fuel-related Consumption and Inventory Report
March 2019

Schedule 6

Description	Darlington	Smith Energy Complex	Harris	Current Month	Total 12 ME March 2019
Coal Data:					
Beginning balance	-	-	-	1,228,431	1,446,194
Tons received during period	-	-	-	426,223	3,611,686
Inventory adjustments	-	-	-	-	(53,917)
Tons burned during period	-	-	-	285,219	3,634,528
Ending balance	-	-	-	1,369,435	1,369,435
MBTUs per ton burned	-	-	-	25.29	25.22
Cost of ending inventory ($/ton)	-	-	-	87.25	87.25
Oil Data:					
Beginning balance	10,427,173	8,183,597	272,031	38,601,682	38,156,552
Gallons received during period	-	-	-	466,344	8,704,526
Miscellaneous use and adjustments	-	-	-	(15,590)	(190,076)
Gallons burned during period	5,871	7,810	-	416,469	8,035,035
Ending balance	10,421,302	8,175,787	272,031	38,635,967	38,635,967
Cost of ending inventory ($/gal)	2.39	2.33	2.42	2.38	2.38
Natural Gas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	13,020	4,496,490	-	12,458,271	177,403,519
MCF burned during period	13,020	4,496,490	-	12,458,271	177,403,519
Ending balance	-	-	-	-	-
Biogas Data:					
Beginning balance	-	-	-	-	-
MCF received during period	-	4,280	-	4,280	30,605
MCF burned during period	-	4,280	-	4,280	30,605
Ending balance	-	-	-	-	-
Limestone/Lime Data:					
Beginning balance	-	-	-	92,164	127,587
Tons received during period	-	-	-	10,600	202,258
Inventory adjustments	-	-	-	-	(3,989)
Tons consumed during period	-	-	-	18,188	241,280
Ending balance	-	-	-	84,576	84,576
Cost of ending inventory ($/ton)	-	-	-	45.35	45.35

Schedule 7

DUKE ENERGY PROGRESS
ANALYSIS OF COAL PURCHASED
MARCH 2019

STATION	TYPE	QUANTITY OF TONS DELIVERED	DELIVERED COST	DELIVERED COST PER TON
ASHEVILLE	SPOT	11,285	$ 1,081,014	$ 95.79
	CONTRACT	46,167	3,335,178	72.24
	FIXED TRANSPORTATION/ADJUSTMENTS	-	804,814	-
	TOTAL	57,452	5,221,006	90.88
MAYO	SPOT	-	-	-
	CONTRACT	115,986	7,676,160	66.18
	FIXED TRANSPORTATION/ADJUSTMENTS	-	806,763	-
	TOTAL	115,986	8,482,923	73.14
ROXBORO	SPOT	12,785	923,729	72.25
	CONTRACT	240,000	16,160,146	67.33
	FIXED TRANSPORTATION/ADJUSTMENTS	-	3,848,587	-
	TOTAL	252,785	20,932,462	82.81
ALL PLANTS	SPOT	24,070	2,004,743	83.29
	CONTRACT	402,153	27,171,484	67.57
	FIXED TRANSPORTATION/ADJUSTMENTS	-	5,460,164	-
	TOTAL	426,223	$ 34,636,391	$ 81.26

Schedule 8

DUKE ENERGY PROGRESS

ANALYSIS OF COAL QUALITY RECEIVED

MARCH 2019

STATION	PERCENT MOISTURE	PERCENT ASH	HEAT VALUE	PERCENT SULFUR
ASHEVILLE	6.98	10.30	12,467	1.64
MAYO	5.90	7.81	13,026	2.68
ROXBORO	6.34	9.94	12,528	1.80

Schedule 9

DUKE ENERGY PROGRESS
ANALYSIS OF OIL PURCHASED
MARCH 2019

	ASHEVILLE	MAYO	ROXBORO	WEATHERSPOON
VENDOR	Indigo	Greensboro Tank Farm	Greensboro Tank Farm	Indigo
SPOT/CONTRACT	Contract	Contract	Contract	Contract
SULFUR CONTENT %	0	0	0	0
GALLONS RECEIVED	(50)	195,583	218,223	52,588
TOTAL DELIVERED COST	$ (99)	$ 404,633	$ 451,673	$ 108,542
DELIVERED COST/GALLON	$ 1.98	$ 2.07	$ 2.07	$ 2.06
BTU/GALLON	138,000	138,000	138,000	138,000

Notes:

A price adjustment of $2,331 for the Brunswick station is excluded.

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2018 - March, 2019
Nuclear Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Brunswick 1	7,819,962	938	95.17	96.00
Brunswick 2	6,876,141	932	84.22	87.43
Harris 1	7,787,575	940	94.59	90.44
Robinson 2	5,264,471	741	81.10	78.71

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2018 through March, 2019
Combined Cycle Units

Unit Name		Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Lee Energy Complex	1A	1,423,723	225	72.23	80.19
Lee Energy Complex	1B	1,430,643	227	71.95	79.56
Lee Energy Complex	1C	1,449,864	228	72.59	79.30
Lee Energy Complex	ST1	2,839,979	379	85.54	91.89
Lee Energy Complex	Block Total	7,144,209	1,059	77.01	84.05
Richmond County CC	7	1,242,500	190	74.56	82.37
Richmond County CC	8	1,232,784	190	73.98	82.31
Richmond County CC	ST4	1,387,299	177	89.61	91.20
Richmond County CC	9	1,414,983	216	74.78	80.18
Richmond County CC	10	1,427,236	216	75.43	80.50
Richmond County CC	ST5	1,840,903	248	84.74	90.61
Richmond County CC	Block Total	8,545,705	1,237	78.85	84.54
Sutton Energy Complex	1A	1,129,922	224	57.58	71.58
Sutton Energy Complex	1B	1,102,837	224	56.20	67.19
Sutton Energy Complex	ST1	1,216,696	271	51.25	64.56
Sutton Energy Complex	Block Total	3,449,455	719	54.77	67.56

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2018 through March, 2019

Intermediate Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Equivalent Availability (%)
Mayo 1	1,350,056	746	20.66	66.37
Roxboro 2	1,555,700	673	26.39	79.51
Roxboro 3	1,374,062	698	22.47	57.68
Roxboro 4	1,960,487	711	31.48	64.47

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2018 through March, 2019
Other Cycling Steam Units

Unit Name	Net Generation (mWh)	Capacity Rating (mW)	Capacity Factor (%)	Operating Availability (%)
Asheville 1	682,433	192	40.57	93.57
Asheville 2	564,038	192	33.54	93.81
Roxboro 1	648,835	380	19.49	88.95

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Power Plant Performance Data
Twelve Month Summary
April, 2018 through March, 2019
Combustion Turbine Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Asheville CT	442,747	370	75.11
Blewett CT	-185	68	98.31
Darlington CT	152,757	825	85.44
Richmond County CT	2,892,244	934	86.50
Sutton Fast Start CT	179,798	98	87.91
Wayne County CT	378,117	963	95.72
Weatherspoon CT	374	164	93.83

Notes:
- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Power Plant Performance Data

Twelve Month Summary
April, 2018 through March, 2019
Hydroelectric Stations

Station Name	Net Generation (mWh)	Capacity Rating (mW)	Operating Availability (%)
Blewett	58,217	27.0	45.80
Marshall	-365	4.0	0.00
Tillery	294,593	84.0	92.24
Walters	495,961	113.0	81.43

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Base Load Power Plant Performance Review Plan

Period: March, 2019

Station	Unit	Date of Outage	Duration of Outage	Scheduled / Unscheduled	Cause of Outage	Reason Outage Occurred	Remedial Action Taken
Brunswick	1	03/28/2019 - 04/01/2019	79.95	Unscheduled	Forced outage due to drywell leak	Failed instrument coupling.	Replace failed coupling and complete an extent of condition review.
	2	03/02/2019 - 04/01/2019	719.00	Scheduled	End-of-cycle 24 refueling outage	Planned refueling outage.	None, planned outage.
Harris	1	None					
Robinson	2	None					

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2019

Lee Energy Complex

No Outages at Baseload Units During the Month.

Richmond County Station

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
7	2/23/2019 3:00:00 AM To 3/8/2019 9:25:00 PM	Sch	5272	Gas Turbine - Boroscope Inspection	Borescope and BOP outage.	
8	2/23/2019 3:00:00 AM To 3/8/2019 11:23:00 PM	Sch	5272	Gas Turbine - Boroscope Inspection	Borescope and BOP outage.	
ST4	2/23/2019 2:58:00 AM To 3/9/2019 12:38:00 AM	Sch	5272	Gas Turbine - Boroscope Inspection	Borescope inspections on U7, U8 and BOP outage.	
9	3/16/2019 4:03:00 AM To 4/1/2019 12:00:00 AM	Sch	5260	Major Gas Turbine Overhaul	CTmajor, BOP and ST major.	
10	3/16/2019 4:03:00 AM To 4/1/2019 12:00:00 AM	Sch	5260	Major Gas Turbine Overhaul	CTmajor, BOP and ST major.	
ST5	3/16/2019 3:54:00 AM To 4/1/2019 12:00:00 AM	Sch	4400	Major Turbine Overhaul (720 Hours Or Longer)	CTmajor, BOP and ST major.	

Sutton Energy Complex

Unit	Duration of Outage	Type of Outage	Cause of Outage		Reason Outage Occurred	Remedial Action Taken
ST1	3/14/2019 6:53:00 PM To 3/14/2019 7:10:00 PM	Unsch	4099	Other High Pressure Turbine Problems	Cold Reheat Temp tripped STG	

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Base Load Power Plant Performance Review Plan

March 2019
Brunswick Nuclear Station

	Unit 1		Unit 2	
(A) MDC (mW)	938		932	
(B) Period Hours	743		743	
(C) Net Gen (mWh) and Capacity Factor (%)	640,194	91.86	13,664	1.97
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00	670,108	96.77
* (E) Net mWh Not Gen due to Partial Scheduled Outages	0	0.00	8,534	1.23
(F) Net mWh Not Gen due to Full Forced Outages	74,993	10.76	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-18,253	-2.62	170	0.03
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00	0	0.00
* (I) Core Conservation	0	0.00	0	0.00
(J) Net mWh Possible in Period	696,934	100.00%	692,476	100.00%
(K) Equivalent Availability (%)		89.08		2.72
(L) Output Factor (%)		102.93		61.09
(M) Heat Rate (BTU/NkWh)		10,485		14,754

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

March 2019
Harris Nuclear Station

	Unit 1	
(A) MDC (mW)	964	
(B) Period Hours	743	
(C) Net Gen (mWh) and Capacity Factor (%)	737,793	103.01
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00
* (E) Net mWh Not Gen due to Partial Scheduled Outages	0	0.00
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-21,541	-3.01
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	716,252	100.00%
(K) Equivalent Availability (%)		100.00
(L) Output Factor (%)		103.01
(M) Heat Rate (BTU/NkWh)		10,119

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

March 2019
Robinson Nuclear Station

	Unit 2	
(A) MDC (mW)	741	
(B) Period Hours	743	
(C) Net Gen (mWh) and Capacity Factor (%)	587,358	106.68
(D) Net mWh Not Gen due to Full Schedule Outages	0	0.00
* (E) Net mWh Not Gen due to Partial Scheduled Outages	0	0.00
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-36,795	-6.68
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	550,563	100.00%
(K) Equivalent Availability (%)		100.00
(L) Output Factor (%)		106.68
(M) Heat Rate (BTU/NkWh)		10,097

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2019

Lee Energy Complex

	Unit 1A	Unit 1B	Unit 1C	Unit ST1	Block Total
(A) MDC (mW)	225	227	228	379	1,059
(B) Period Hrs	743	743	743	743	743
(C) Net Generation (mWh)	144,726	143,181	145,742	276,503	710,152
(D) Capacity Factor (%)	86.57	84.89	86.03	98.19	90.25
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	20,433	21,175	21,547	371	63,526
(H) Scheduled Derates: percent of Period Hrs	12.22	12.56	12.72	0.13	8.07
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	2,017	4,305	2,115	4,723	13,159
(N) Economic Dispatch: percent of Period Hrs	1.21	2.55	1.25	1.68	1.67
(O) Net mWh Possible in Period	167,175	168,661	169,404	281,597	786,837
(P) Equivalent Availability (%)	87.78	87.44	87.28	99.87	91.93
(Q) Output Factor (%)	86.57	84.89	86.03	98.19	90.25
(R) Heat Rate (BTU/NkWh)	8,727	8,767	8,728	4,600	7,128

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2019

Richmond County Station

	Unit 7	Unit 8	Unit ST4	Block Total
(A) MDC (mW)	194	194	182	570
(B) Period Hrs	743	743	743	743
(C) Net Generation (mWh)	89,949	89,752	98,060	277,761
(D) Capacity Factor (%)	62.40	62.27	72.52	65.59
(E) Net mWh Not Generated due to Full Scheduled Outages	36,747	37,128	35,059	108,934
(F) Scheduled Outages: percent of Period Hrs	25.49	25.76	25.93	25.72
(G) Net mWh Not Generated due to Partial Scheduled Outages	11,072	11,308	3,577	25,957
(H) Scheduled Derates: percent of Period Hrs	7.68	7.85	2.65	6.13
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	6,375	5,953	0	12,328
(N) Economic Dispatch: percent of Period Hrs	4.42	4.13	0.00	2.91
(O) Net mWh Possible in Period	144,142	144,142	135,226	423,510
(P) Equivalent Availability (%)	66.83	66.40	71.43	68.15
(Q) Output Factor (%)	83.76	83.87	97.90	88.30
(R) Heat Rate (BTU/NkWh)	11,095	11,074	0	7,171

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2019

Richmond County Station

	Unit 9	Unit 10	Unit ST5	Block Total
(A) MDC (mW)	216	216	248	680
(B) Period Hrs	743	743	743	743
(C) Net Generation (mWh)	66,681	67,016	82,731	216,428
(D) Capacity Factor (%)	41.55	41.76	44.90	42.84
(E) Net mWh Not Generated due to Full Scheduled Outages	82,069	82,069	94,265	258,403
(F) Scheduled Outages: percent of Period Hrs	51.14	51.14	51.16	51.14
(G) Net mWh Not Generated due to Partial Scheduled Outages	7,624	7,443	0	15,067
(H) Scheduled Derates: percent of Period Hrs	4.75	4.64	0.00	2.98
(I) Net mWh Not Generated due to Full Forced Outages	0	0	0	0
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	4,114	3,960	7,268	15,342
(N) Economic Dispatch: percent of Period Hrs	2.56	2.47	3.94	3.04
(O) Net mWh Possible in Period	160,488	160,488	184,264	505,240
(P) Equivalent Availability (%)	44.11	44.23	48.84	45.87
(Q) Output Factor (%)	85.03	85.46	91.92	87.68
(R) Heat Rate (BTU/NkWh)	11,417	11,320	0	7,023

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
March 2019

Sutton Energy Complex

	Unit 1A	Unit 1B	Unit ST1	Block Total
(A) MDC (mW)	224	224	271	719
(B) Period Hrs	743	743	743	743
(C) Net Generation (mWh)	131,326	131,593	145,349	408,268
(D) Capacity Factor (%)	78.91	79.07	72.19	76.42
(E) Net mWh Not Generated due to Full Scheduled Outages	0	0	0	0
(F) Scheduled Outages: percent of Period Hrs	0.00	0.00	0.00	0.00
(G) Net mWh Not Generated due to Partial Scheduled Outages	20,061	19,689	1,857	41,607
(H) Scheduled Derates: percent of Period Hrs	12.05	11.83	0.92	7.79
(I) Net mWh Not Generated due to Full Forced Outages	0	0	77	77
(J) Forced Outages: percent of Period Hrs	0.00	0.00	0.04	0.01
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	0
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.00
(M) Net mWh Not Generated due to Economic Dispatch	15,045	15,150	54,070	84,265
(N) Economic Dispatch: percent of Period Hrs	9.04	9.10	26.85	15.77
(O) Net mWh Possible in Period	166,432	166,432	201,353	534,217
(P) Equivalent Availability (%)	87.95	88.17	99.04	92.20
(Q) Output Factor (%)	80.79	80.88	74.49	78.46
(R) Heat Rate (BTU/NkWh)	10,994	10,972	0	7,073

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Progress
Intermediate Power Plant Performance
Review Plan
March 2019

		Mayo Station
		Unit 1
(A)	MDC (mW)	746
(B)	Period Hrs	743
(C)	Net Generation (mWh)	66,070
(D)	Net mWh Possible in Period	554,278
(E)	Equivalent Availability (%)	88.61
(F)	Output Factor (%)	48.64
(G)	Capacity Factor (%)	11.92

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Intermediate Power Plant Performance
Review Plan
March 2019

Roxboro Station

	Unit 2	Unit 3	Unit 4
(A) MDC (mW)	673	698	711
(B) Period Hrs	743	743	743
(C) Net Generation (mWh)	-5,253	104,530	357,456
(D) Net mWh Possible in Period	500,039	518,614	528,273
(E) Equivalent Availability (%)	100.00	36.00	96.26
(F) Output Factor (%)	0.00	60.59	70.24
(G) Capacity Factor (%)	0.00	20.16	67.67

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Base Load Power Plant Performance Review Plan

April 2018 - March 2019
Brunswick Nuclear Station

	Unit 1		Unit 2	
(A) MDC (mW)	938		932	
(B) Period Hours	8760		8760	
(C) Net Gen (mWh) and Capacity Factor (%)	7,819,962	95.17	6,876,141	84.22
(D) Net mWh Not Gen due to Full Schedule Outages	81,262	0.99	670,108	8.21
* (E) Net mWh Not Gen due to Partial Scheduled Outages	44,629	0.54	82,363	1.01
(F) Net mWh Not Gen due to Full Forced Outages	331,693	4.04	252,868	3.10
* (G) Net mWh Not Gen due to Partial Forced Outages	-60,666	-0.74	282,840	3.46
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00	0	0.00
* (I) Core Conservation	0	0.00	0	0.00
(J) Net mWh Possible in Period	8,216,880	100.00%	8,164,320	100.00%
(K) Equivalent Availability (%)		96.00		87.43
(L) Output Factor (%)		100.21		94.96
(M) Heat Rate (BTU/NkWh)		10,416		10,798

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

April 2018 - March 2019
Harris Nuclear Station

	Unit 1	
(A) MDC (mW)	964	
(B) Period Hours	8760	
(C) Net Gen (mWh) and Capacity Factor (%)	7,787,575	94.59
(D) Net mWh Not Gen due to Full Schedule Outages	756,318	9.19
* (E) Net mWh Not Gen due to Partial Scheduled Outages	20,006	0.24
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-330,491	-4.02
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	8,233,408	100.00%
(K) Equivalent Availability (%)		90.44
(L) Output Factor (%)		104.23
(M) Heat Rate (BTU/NkWh)		10,226

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant Performance Review Plan

April 2018 - March 2019
Robinson Nuclear Station

	Unit 2	
(A) MDC (mW)	741	
(B) Period Hours	8760	
(C) Net Gen (mWh) and Capacity Factor (%)	5,264,471	81.10
(D) Net mWh Not Gen due to Full Schedule Outages	1,297,442	19.99
* (E) Net mWh Not Gen due to Partial Scheduled Outages	99,165	1.53
(F) Net mWh Not Gen due to Full Forced Outages	0	0.00
* (G) Net mWh Not Gen due to Partial Forced Outages	-169,918	-2.62
* (H) Net mWh Not Gen due to Economic Dispatch	0	0.00
* (I) Core Conservation	0	0.00
(J) Net mWh Possible in Period	6,491,160	100.00%
(K) Equivalent Availability (%)		78.71
(L) Output Factor (%)		101.36
(M) Heat Rate (BTU/NkWh)		10,476

* Estimate
FOOTNOTE: D and F Include Ramping Losses

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2018 through March, 2019

Lee Energy Complex

	Unit 1A	Unit 1B	Unit 1C	Unit ST1	Block Total
(A) MDC (mW)	225	227	228	379	1,059
(B) Period Hrs	8,760	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,423,723	1,430,643	1,449,864	2,839,979	7,144,209
(D) Capacity Factor (%)	72.23	71.95	72.59	85.54	77.01
(E) Net mWh Not Generated due to Full Scheduled Outages	73,316	85,738	88,863	132,069	379,986
(F) Scheduled Outages: percent of Period Hrs	3.72	4.31	4.45	3.98	4.10
(G) Net mWh Not Generated due to Partial Scheduled Outages	271,178	283,193	288,469	49,253	892,092
(H) Scheduled Derates: percent of Period Hrs	13.76	14.24	14.44	1.48	9.62
(I) Net mWh Not Generated due to Full Forced Outages	45,975	37,561	36,096	78,529	198,161
(J) Forced Outages: percent of Period Hrs	2.33	1.89	1.81	2.37	2.14
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	0	9,254	9,254
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.00	0.28	0.10
(M) Net mWh Not Generated due to Economic Dispatch	156,808	151,385	133,988	210,957	653,138
(N) Economic Dispatch: percent of Period Hrs	7.96	7.61	6.71	6.35	7.04
(O) Net mWh Possible in Period	1,971,000	1,988,520	1,997,280	3,320,040	9,276,840
(P) Equivalent Availability (%)	80.19	79.56	79.30	91.89	84.05
(Q) Output Factor (%)	78.54	77.06	77.80	91.79	82.81
(R) Heat Rate (BTU/NkWh)	9,013	9,096	9,010	4,572	7,263

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2018 through March, 2019

Richmond County Station

	Unit 7	Unit 8	Unit ST4	Block Total
(A) MDC (mW)	190	190	177	557
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,242,500	1,232,784	1,387,299	3,862,583
(D) Capacity Factor (%)	74.56	73.98	89.61	79.14
(E) Net mWh Not Generated due to Full Scheduled Outages	103,816	93,362	60,727	257,904
(F) Scheduled Outages: percent of Period Hrs	6.23	5.60	3.92	5.28
(G) Net mWh Not Generated due to Partial Scheduled Outages	175,091	179,560	59,403	414,053
(H) Scheduled Derates: percent of Period Hrs	10.51	10.78	3.84	8.48
(I) Net mWh Not Generated due to Full Forced Outages	15,578	22,448	5,014	43,040
(J) Forced Outages: percent of Period Hrs	0.93	1.35	0.32	0.88
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	12,850	12,850
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.83	0.26
(M) Net mWh Not Generated due to Economic Dispatch	129,451	138,281	22,819	290,552
(N) Economic Dispatch: percent of Period Hrs	7.77	8.30	1.47	5.95
(O) Net mWh Possible in Period	1,666,435	1,666,435	1,548,113	4,880,983
(P) Equivalent Availability (%)	82.37	82.31	91.20	85.09
(Q) Output Factor (%)	80.63	80.52	94.01	84.93
(R) Heat Rate (BTU/NkWh)	11,328	11,164	0	7,207

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2018 through March, 2019

Richmond County Station

	Unit 9	Unit 10	Unit ST5	Block Total
(A) MDC (mW)	216	216	248	680
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,414,983	1,427,236	1,840,903	4,683,122
(D) Capacity Factor (%)	74.78	75.43	84.74	78.62
(E) Net mWh Not Generated due to Full Scheduled Outages	172,670	174,442	202,083	549,195
(F) Scheduled Outages: percent of Period Hrs	9.13	9.22	9.30	9.22
(G) Net mWh Not Generated due to Partial Scheduled Outages	198,417	194,176	0	392,593
(H) Scheduled Derates: percent of Period Hrs	10.49	10.26	0.00	6.59
(I) Net mWh Not Generated due to Full Forced Outages	3,920	277	0	4,198
(J) Forced Outages: percent of Period Hrs	0.21	0.01	0.00	0.07
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	1,848	1,848
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.09	0.03
(M) Net mWh Not Generated due to Economic Dispatch	102,169	96,030	127,646	325,845
(N) Economic Dispatch: percent of Period Hrs	5.40	5.08	5.88	5.47
(O) Net mWh Possible in Period	1,892,160	1,892,160	2,172,480	5,956,800
(P) Equivalent Availability (%)	80.18	80.50	90.61	84.09
(Q) Output Factor (%)	82.97	83.12	93.43	86.84
(R) Heat Rate (BTU/NkWh)	11,311	11,252	0	6,847

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Progress
Base Load Power Plant
Performance Review Plan
April, 2018 through March, 2019

Sutton Energy Complex

	Unit 1A	Unit 1B	Unit ST1	Block Total
(A) MDC (mW)	224	224	271	719
(B) Period Hrs	8,760	8,760	8,760	8,760
(C) Net Generation (mWh)	1,129,922	1,102,837	1,216,696	3,449,455
(D) Capacity Factor (%)	57.58	56.20	51.25	54.77
(E) Net mWh Not Generated due to Full Scheduled Outages	204,202	273,175	242,491	719,868
(F) Scheduled Outages: percent of Period Hrs	10.41	13.92	10.21	11.43
(G) Net mWh Not Generated due to Partial Scheduled Outages	220,747	203,720	16,716	441,183
(H) Scheduled Derates: percent of Period Hrs	11.25	10.38	0.70	7.00
(I) Net mWh Not Generated due to Full Forced Outages	132,765	166,996	569,552	869,312
(J) Forced Outages: percent of Period Hrs	6.77	8.51	23.99	13.80
(K) Net mWh Not Generated due to Partial Forced Outages	0	0	12,685	12,685
(L) Forced Derates: percent of Period Hrs	0.00	0.00	0.53	0.20
(M) Net mWh Not Generated due to Economic Dispatch	274,604	215,512	315,820	805,936
(N) Economic Dispatch: percent of Period Hrs	13.99	10.98	13.30	12.80
(O) Net mWh Possible in Period	1,962,240	1,962,240	2,373,960	6,298,440
(P) Equivalent Availability (%)	71.58	67.19	64.56	67.56
(Q) Output Factor (%)	77.34	77.94	78.28	77.86
(R) Heat Rate (BTU/NkWh)	11,366	11,373	0	7,359

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.
- (R) Includes Light Off BTU's

Duke Energy Progress
Intermediate Power Plant
Performance Review Plan
April, 2018 through March, 2019

	Mayo Station
Units	**Unit 1**
(A) MDC (mW)	746
(B) Period Hrs	8,760
(C) Net Generation (mWh)	1,350,056
(D) Net mWh Possible in Period	6,534,960
(E) Equivalent Availability (%)	66.37
(F) Output Factor (%)	37.55
(G) Capacity Factor (%)	20.66

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

Duke Energy Progress
Intermediate Power Plant
Performance Review Plan
April, 2018 through March, 2019

Roxboro Station

Units		Unit 2	Unit 3	Unit 4
(A)	MDC (mW)	673	698	711
(B)	Period Hrs	8,760	8,760	8,760
(C)	Net Generation (mWh)	1,555,700	1,374,062	1,960,487
(D)	Net mWh Possible in Period	5,895,480	6,114,480	6,228,360
(E)	Equivalent Availability (%)	79.51	57.68	64.47
(F)	Output Factor (%)	49.91	49.96	56.50
(G)	Capacity Factor (%)	26.39	22.47	31.48

Notes:

- Units in commercial operation for the full month are presented. Pre-commercial or partial month commercial operations are not included.

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Proposed Nuclear Capacity Factor
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 1

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs	7,500,998	8,022,954	8,298,420	5,890,772	29,713,145
Cost	$ 45,226,821	$ 47,347,803	$ 56,256,531	$ 34,493,536	$ 183,324,690
$/MWhs	$ 6.0294	$ 5.9015	$ 6.7792	$ 5.8555	
Avg. $/MWhs					$ 6.1698
Cents per kWh					0.6170

	Unit		Dec'19-Nov'20
MDC			
	Brunswick 1	MW	938
	Brunswick 2	MW	932
	Harris 1	MW	964
	Robinson 1	MW	741
			3,575
Hours in Year			8,784
Generation in GWhs			
	Brunswick 1	GWh	7,501
	Brunswick 2	GWh	8,023
	Harris 1	GWh	8,298
	Robinson 1	GWh	5,891
			29,713
	Proposed Nuclear Capacity Factor		94.62%

Note: Totals may not sum due to rounding

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
NERC 5 Year Average Nuclear Capacity Factor
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 2

	Brunswick 1	Brunswick 2	Harris 1	Robinson 1	Total
MWhs with NERC applied	7,777,986	7,728,233	7,743,781	5,576,863	28,826,864
Hours in Year	8,784	8,784	8,784	8,784	8,784
MDC	938	932	964	741	3,575
Capacity Factor-NERC 5yr Avg	0.9440	0.944	0.9145	0.8568	
Cost ($)	$ 47,988,756	$ 47,681,792	$ 47,777,718	$ 34,408,229	$ 177,856,495
Avg. $/MWHs					$ 6.1698
Cents per kWh					0.6170

	Capacity Rating	NCF Rating	Weighted Average
Brunswick 1	938	94.40%	24.77%
Brunswick 2	932	94.40%	24.61%
Harris 1	964	91.45%	24.66%
Robinson 1	741	85.68%	17.76%
	3,575		91.80%

I/A

DUKE ENERGY PROGRESS, LLC — **Harrington Workpaper 3**

North Carolina Annual Fuel and Fuel Related Expense
North Carolina Generation in MWhs
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Resource Type		MWh Dec'19-Nov'20
Nuclear		29,600,524
Adjust for Higher Nuclear Capacity Factor		112,622
Adjusted Nuclear Total		29,713,146
Coal		11,243,908
Adjust for Higher Nuclear Capacity Factor		(112,622)
Adjusted Coal Total		11,131,286
Gas CT and CC Total		22,185,181
Total Hydro		648,112
Utility Owned Solar Generation		279,675
Total Net Generation		63,957,400
Purchases	287,950	
Purchases for REPS Compliance	2,984,954	
Purchases from Qualifying Facilities	3,766,456	
Allocated Economic Purchases	168,026	
Joint Dispatch purchases	352,984	7,560,370
Total Net Generation and Purchases		71,517,770
Sales Totals (intersystem sales, JDA sales)		(7,544,324)
Line Losses and Company Use		(1,817,527)
Total NC System Sales		**62,155,919**

Note: Totals may not sum due to rounding

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Fuel Costs ($)
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 4

Resource Type		Costs $ Dec'19-Nov'20
Nuclear		$ 182,708,089
Adjust for Higher Nuclear Capacity Factor		616,601
Adjusted Nuclear		183,324,690
Coal		352,524,698
Adjust for Higher Nuclear Capacity Factor		(3,530,975)
Adjusted Coal Total		348,993,723
Reagent and By-Product Costs		26,265,057
Gas CT and CC Total		591,960,856
Total Hydro		-
Utility Owned Solar Generation		-
Total Generation Costs		1,150,544,326
Purchases	$ 14,160,859	
Purchases for REPS Compliance	168,625,939	
Purchases for REPS Compliance Capacity	34,622,728	
Purchases from Qualifying Facilities Energy	193,990,299	
Purchases from Qualifying Facilities Capacity	39,793,114	
Allocated Economic Purchases	5,318,328	
Joint Dispatch Purchases	7,856,766	
Joint Dispatch Savings	(21,960,626)	$ 442,407,406
Total Net Generation and Purchases		1,592,951,732
Sales Totals (intersystem sales)	$ (9,482,483)	
Fuel Transfer Sales	(151,549,522)	(161,032,005)
Total System Fuel and Related Expenses		$ 1,431,919,727

Note: Totals may not sum due to rounding

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Reagents ($)
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 5

Month	Year	Ammonia/ Urea	Limestone	Limestone Off-System Sales	Catalyst Depreciation	Magnesium Hydroxide	Calcium Carbonate	Total NC System Reagent Cost	Gypsum (Gain)/Loss	Ash (Gain)/Loss	Total NC System Reagent Cost and ByProduct (Gain)/Loss
December	2019	$ 501,258	$ 856,904	$ (13,875)	$ 131,225	$ 263,707	$ 566,911	$ 2,306,129	$ (159,935)	$ (16,514)	$ 2,129,680
January	2020	592,683	1,032,605	(60,191)	131,225	308,141	664,267	2,668,730	(183,141)	(26,970)	2,458,618
February	2020	564,062	1,015,062	(46,890)	131,225	295,418	627,340	2,586,217	8,224,137	(25,083)	10,785,271
March	2020	220,821	420,575	(13,341)	131,225	116,287	268,209	1,143,776	(38,896)	(7,993)	1,096,887
April	2020	125,700	248,850	(13,623)	130,758	68,966	158,824	719,475	(22,476)	(4,721)	692,278
May	2020	135,515	268,249	(8,647)	130,761	74,608	170,523	771,009	(22,587)	(4,998)	743,425
June	2020	307,837	590,654	(9,998)	129,062	166,913	370,721	1,555,190	(91,698)	(13,733)	1,449,759
July	2020	469,410	904,197	(2,067)	130,557	256,238	544,005	2,302,340	(156,469)	(21,595)	2,124,276
August	2020	444,150	866,174	(5,165)	130,802	243,033	516,617	2,195,611	(152,236)	(20,531)	2,022,844
September	2020	263,756	515,430	(2,417)	130,797	142,429	315,333	1,365,329	(102,025)	(12,865)	1,250,439
October	2020	165,988	324,185	(5,426)	131,100	90,205	198,672	904,724	(69,861)	(8,450)	826,413
November	2020	140,011	266,433	(4,077)	131,225	77,471	155,661	766,725	(73,558)	(8,000)	685,167
12ME Nov	2020	$ 3,931,192	$ 7,309,319	$ (185,717)	$ 1,569,962	$ 2,103,416	$ 4,557,084	$ 19,285,255	$ 7,151,255	$ (171,453)	$ 26,265,057

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Fuel Impacts
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 6

		Positive numbers represent expense, Negative numbers represent revenues							
		Allocated Economic Purchase Cost		Economic Sales Cost		Fuel Transfer Payment		JDA Savings Payment	
Month	Year	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC
December	2019	$ 370,332	$ 526,346	$ (473,650)	$ (80,551)	$ (20,734,306)	$ 20,734,306	$ (2,620,619)	$ 2,620,619
January	2020	$ 805,729	$ 1,120,696	$ (1,322,174)	$ (2,956,749)	$ (2,199,575)	$ 2,199,575	$ (499,078)	$ 499,078
February	2020	$ 468,910	$ 658,964	$ (1,700,288)	$ (1,944,948)	$ (2,966,788)	$ 2,966,788	$ (389,767)	$ 389,767
March	2020	$ 440,334	$ 645,266	$ (317,900)	$ (366,295)	$ (7,807,638)	$ 7,807,638	$ (1,677,115)	$ 1,677,115
April	2020	$ 565,883	$ 861,314	$ (307,322)	$ (42,935)	$ (17,492,082)	$ 17,492,082	$ (3,023,951)	$ 3,023,951
May	2020	$ 318,273	$ 484,205	$ (420,769)	$ (53,391)	$ (15,669,339)	$ 15,669,339	$ (2,463,276)	$ 2,463,276
June	2020	$ 265,020	$ 391,037	$ (266,975)	$ (133,411)	$ (13,367,229)	$ 13,367,229	$ (1,420,206)	$ 1,420,206
July	2020	$ 402,156	$ 570,790	$ (355,561)	$ (554,537)	$ (12,885,849)	$ 12,885,849	$ (1,852,753)	$ 1,852,753
August	2020	$ 503,884	$ 715,819	$ (349,678)	$ (170,188)	$ (12,569,311)	$ 12,569,311	$ (1,395,342)	$ 1,395,342
September	2020	$ 386,514	$ 552,358	$ (206,144)	$ (60,045)	$ (11,359,236)	$ 11,359,236	$ (1,715,765)	$ 1,715,765
October	2020	$ 319,946	$ 470,917	$ (42,092)	$ (45,603)	$ (14,464,750)	$ 14,464,750	$ (3,003,174)	$ 3,003,174
November	2020	$ 471,347	$ 699,707	$ (238,409)	$ (114,001)	$ (12,176,653)	$ 12,176,653	$ (1,899,580)	$ 1,899,580
Total		$ 5,318,328		$ (6,000,962)		$ (143,692,756)		$ (21,960,626)	

Note: Totals may not sum due to rounding

		Fuel Transfer Payments	
		Purchases	Sales
December	2019	$ 174,910	$ 20,909,216
January	2020	$ 3,426,589	$ 5,626,164
February	2020	$ 2,934,054	$ 5,900,842
March	2020	$ 173,089	$ 7,980,727
April	2020	$ 651	$ 17,492,733
May	2020	$ 140,440	$ 15,809,779
June	2020	$ 41,137	$ 13,408,366
July	2020	$ 327,326	$ 13,213,176
August	2020	$ 154,737	$ 12,724,048
September	2020	$ 50,830	$ 11,410,066
October	2020	$ 263,167	$ 14,727,916
November	2020	$ 169,837	$ 12,346,489
		$ 7,856,766	$ 151,549,522
			$ (143,692,756)

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Merger Payments
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 7

Month	Year	MWh Transfer Projection		MWh Purchase Allocation Delta		Adjusted MWh Transfer		Fossil Gen Cost $/MWh		Pre-Net Payments $		Actual Payments $	
		DEP to DEC	DEC to DEP	DEP	DEC	DEP to DEC	DEC to DEP	DEP	DEC	DEP to DEC	DEC to DEP	DEP to DEC	DEC to DEP
December	2019	880,616	7,953	4,764	(4,764)	885,380	7,953	$ 23.62	$ 21.99	$ 174,910	$ 20,909,216	$ -	$ 20,734,306
January	2020	280,440	127,954	(8,459)	8,459	280,440	136,413	$ 20.06	$ 25.12	$ 3,426,589	$ 5,626,164	$ -	$ 2,199,575
February	2020	246,473	109,549	(10,607)	10,607	246,473	120,156	$ 23.94	$ 24.42	$ 2,934,054	$ 5,900,842	$ -	$ 2,966,788
March	2020	485,080	9,971	4,607	(4,607)	489,687	9,971	$ 16.30	$ 17.36	$ 173,089	$ 7,980,727	$ -	$ 7,807,638
April	2020	839,369	44	10,681	(10,681)	850,049	44	$ 20.58	$ 14.88	$ 651	$ 17,492,733	$ -	$ 17,492,082
May	2020	756,005	7,983	8,211	(8,211)	764,216	7,983	$ 20.69	$ 17.59	$ 140,440	$ 15,809,779	$ -	$ 15,669,339
June	2020	621,236	3,230	3,731	(3,731)	624,967	3,230	$ 21.45	$ 12.74	$ 41,137	$ 13,408,366	$ -	$ 13,367,229
July	2020	591,188	22,850	2,247	(2,247)	593,436	22,850	$ 22.27	$ 14.32	$ 327,326	$ 13,213,176	$ -	$ 12,885,849
August	2020	559,731	11,450	14,246	(14,246)	573,978	11,450	$ 22.17	$ 13.51	$ 154,737	$ 12,724,048	$ -	$ 12,569,311
September	2020	560,773	3,782	9,132	(9,132)	569,905	3,782	$ 20.02	$ 13.44	$ 50,830	$ 11,410,066	$ -	$ 11,359,236
October	2020	699,609	16,686	8,585	(8,585)	708,194	16,686	$ 20.80	$ 15.77	$ 263,167	$ 14,727,916	$ -	$ 14,464,750
November	2020	580,820	12,468	8,209	(8,209)	589,029	12,468	$ 20.96	$ 13.62	$ 169,837	$ 12,346,489	$ -	$ 12,176,653
Total		7,101,341	333,918	55,346	(55,346)	7,175,753	352,984			$ 7,856,766	$ 151,549,522	$ -	$ 143,692,756

Note: Totals may not sum due to rounding

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 8

	Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC			
Residential	16,265,079		16,265,079
Small General Service	1,806,876		1,806,876
Medium General Service	10,414,506		10,414,506
Large General Service	9,223,825		9,223,825
Lighting	381,171		381,171
NC Retail	38,091,457		38,091,457
SC Retail	6,739,878	34,790	6,774,668
Total Wholesale	17,324,584		17,324,584
Total Adjusted NC System Sales	62,155,919	34,790	62,190,710
NC as a percentage of total	61.28%	0.00%	61.25%
SC as a percentage of total	10.84%	100.00%	10.89%
Wholesale as a percentage of total	27.87%	0.00%	27.86%

SC Net Metering allocation adjustment			
Total Projected SC NEM MWhs		34,790	
Marginal Fuel rate per MWh for SC NEM	$	32.11	
Fuel Benefit to be directly assigned to SC	$	1,117,119	
System Fuel Expense	$	1,431,919,727	Exh 2 Sch 1 Pg 1
Fuel benefit to be directly assigned to SC Retail		1,117,119	
Total Adjusted System Fuel Expense	$	1,433,036,845	Exh 2 Sch 1 Pg 3

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Normalized Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 8a

	Test Period Sales MWhs	Weather Normalization	Customer Growth	Remove Impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC					
Residential	16,147,005	(245,014)	120,250		16,022,241
Small General Service	1,958,731	(20,261)	5,244		1,943,714
Medium General Service	11,108,152	(136,061)	35,216		11,007,307
Large General Service	8,479,278	(110,973)	238		8,368,542
Lighting	353,410	0	555		353,965
Total	38,046,575	(512,310)	161,504		37,695,769
SC Retail	6,414,956	(85,144)	7,439	34,790	6,372,042
Total Wholesale	18,106,633	(273,277)	126,090		17,959,446
Total Adjusted NC System Sales	62,568,164	(870,731)	295,033	34,790	62,027,257
NC as a percentage of total	60.81%				60.77%
SC as a percentage of total	10.25%				10.27%
Wholesale as a percentage of total	28.94%				28.95%

SC Net Metering allocation adjustment			
Total Projected SC NEM MWhs		34,790	
Marginal Fuel rate per MWh for SC NEM	$	32.11	
Fuel Benefit to be directly assigned to SC	$	1,117,119	
System Fuel Expense	$	1,426,649,465	Exh 2 Sch 2 Pg 1
Fuel benefit to be directly assigned to SC Retail		1,117,119	
Total Adjusted System Fuel Expense	$	1,427,766,584	Exh 2 Sch 2 Pg 3

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Projected Sales - NERC 5 year Average
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 8b

		Projection MWhs	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC				
	Residential	16,265,079		16,265,079
	Small General Service	1,806,876		1,806,876
	Medium General Service	10,414,506		10,414,506
	Large General Service	9,223,825		9,223,825
	Lighting	381,171		381,171
Total		38,091,457		38,091,457
SC Retail		6,739,878	34,790	6,774,668
Total Wholesale		17,324,584		17,324,584
Total Adjusted NC System Sales		62,155,919	34,790	62,190,710
NC as a percentage of total		61.28%	0.00%	61.25%
SC as a percentage of total		10.84%	100.00%	10.89%
Wholesale as a percentage of total		27.87%	0.00%	27.86%

SC Net Metering allocation adjustment			
Total Projected SC NEM MWhs		34,790	
Marginal Fuel rate per MWh for SC NEM	$	32.11	
Fuel Benefit to be directly assigned to SC	$	1,117,119	
System Fuel Expense	$	1,454,238,675	Exh 2 Sch 3 Pg 1
Fuel benefit to be directly assigned to SC Retail		1,117,119	
Total Adjusted System Fuel Expense	$	1,455,355,794	Exh 2 Sch 3 Pg 3

I/A

Harrington Workpaper 9

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adustment - MWh
Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Rate Schedule	Reference	NC Proposed MWH [1] Adjustment	SC Proposed MWH Adjustment	Wholesale Proposed MWH Adjustment
Residential	RES	120,250	7,814	
General:				
General Service Small	SGS	5,244	(2,492)	
General Service Medium	MGS	35,216	2,162	
Total General		40,460	(330)	
Lighting:				
Street Lighting	SLS/SLR	417	11	
Sports Field Lighting	SFLS	95	(6)	
Traffic Signal Service	TSS/TFS	42	(50)	
Total Street Lighting		555	(44)	
Industrial:				
I - Textile	LGS	-	-	
I - Nontextile	LGS	238	-	
Total Industrial		238	-	
Total		161,504	7,439	126,090

[1] Using the regression method (Residential, Lighting, SGS classes) and a customer by customer method for MGS and Industrial.

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
NC Retail Allocation %
Energy Allocation Factors - 12 Months Ending December 31, 2018
Docket No. E-2, Sub 1204

	kWh @ Meter	E-2 Allocation	kWh @ Prod Out.	E-1 Allocation	Losses
NC RES	16,158,859,096	0.253513	16,886,868,234	0.256060	728,009,138
NC RES-TOU	507,187,493	0.007957	530,037,939	0.008037	22,850,446
NC SGS	1,950,982,004	0.030609	2,038,860,205	0.030916	87,878,201
NC SGS-CLR	31,614,397	0.000496	33,038,728	0.000501	1,424,331
NC MGS-TOU	8,371,865,197	0.131344	8,732,655,226	0.132416	360,790,029
NC MGS	2,807,099,681	0.044040	2,930,697,735	0.044439	123,598,054
NC SI	43,075,313	0.000676	44,807,202	0.000679	1,731,889
NC LGS	1,141,204,433	0.017904	1,182,461,085	0.017930	41,256,652
NC LGS-TOU	1,598,681,135	0.025081	1,654,866,445	0.025093	56,185,310
NC LGS-RTP	5,717,905,454	0.089707	5,891,608,297	0.089336	173,702,843
NC TSS	4,754,792	0.000075	4,969,011	0.000075	214,219
NC ALS	267,795,639	0.004201	279,860,703	0.004244	12,065,064
NC SLS	85,107,971	0.001335	88,942,362	0.001349	3,834,391
NC SFLS	1,134,908	0.000018	1,175,511	0.000018	40,603
Total NCR	38,687,267,513	0.606957	40,300,848,683	0.611093	1,613,581,170
NCEMPA	7,640,609,496	0.119872	7,781,142,553	0.117988	140,533,057
NCEMC	7,861,748,196	0.123341	8,006,348,638	0.121403	144,600,442
Fayetteville	2,134,092,683	0.033481	2,173,344,861	0.032955	39,252,179
FBEMC	548,372,445	0.008603	558,458,611	0.008468	10,086,166
Piedmont EMC	76,153,133	0.001195	77,553,811	0.001176	1,400,678
Haywood EMC	83,779,955	0.001314	85,320,912	0.001294	1,540,957
Total NCWHS	10,704,146,412	0.167935	10,901,026,834	0.165295	196,880,422
Total NC	57,032,023,421	0.894764	58,983,018,069	0.894376	1,950,994,648
SC RES	2,148,532,519	0.033708	2,245,330,894	0.034047	96,798,375
SC RET	41,479,049	0.000651	43,347,815	0.000657	1,868,766
SC SGS	278,936,083	0.004376	291,483,609	0.004420	12,547,526
SC SGS-CLR	4,439,514	0.000070	4,639,529	0.000070	200,015
SC MGS-TOU	1,115,225,685	0.017497	1,163,034,915	0.017635	47,809,230
SC MGS	537,836,914	0.008438	561,105,498	0.008508	23,268,584
SC SI	18,492,882	0.000290	19,221,900	0.000291	729,018
SC LGS	698,027,189	0.010951	723,387,192	0.010969	25,360,003
SC LGS-TOU	309,355,839	0.004853	318,750,549	0.004833	9,394,710
SC LGS-CRTL-TOU	702,376,100	0.011019	720,122,869	0.010919	17,746,769
SC LGS-RTP	571,293,865	0.008963	586,269,865	0.008890	14,976,000
SC TSS	855,613	0.000013	894,161	0.000014	38,548
SC ALS	63,427,856	0.000995	66,285,487	0.001005	2,857,631
SC SLS	16,316,405	0.000256	17,051,512	0.000259	735,107
SC SFLS	149,692	0.000002	155,048	0.000002	5,356
Total SCR	6,506,745,205	0.102083	6,761,080,842	0.102520	254,335,637
SCWHS (Camden)	200,980,232	0.003153	204,676,844	0.003104	3,696,612
Total SC	6,707,725,437	0.105236	6,965,757,686	0.105624	258,032,249
Total System	63,739,748,858	1.000000	65,948,775,755	1.000000	2,209,026,897

Cost of Service Data Summarized	kWh @ Meter	kWh @ Prod Out.	Losses (kWh)	Loss Percent
Residential	16,666,046,589	17,416,906,173	750,859,584	4.51%
SGS	1,987,351,193	2,076,867,944	89,516,751	4.50%
MGS	11,222,040,191	11,708,160,163	486,119,972	4.33%
LGS	8,457,791,022	8,728,935,826	271,144,804	3.21%
Lighting	354,038,518	369,978,576	15,940,058	4.50%
Total NC Retail	38,687,267,513	40,300,848,683	1,613,581,170	4.17%
Total NC Retail	38,687,267,513	40,300,848,683	1,613,581,170	4.17%
SC Retail	6,506,745,205	6,761,080,842	254,335,637	3.91%
NEM Generation	18,558,183	19,313,093	754,910	
Total SC Retail	6,525,303,388	6,780,393,935	255,090,547	3.91%
All other jurisdications	18,527,177,957	18,867,533,137	340,355,180	1.84%
Total System	63,739,748,858	65,948,775,755	2,209,026,897	3.47%

Line Loss Calculations for Projected Fuel Costs	MWh @ Meter	MWh @ Prod Out.	Losses (MWh)	Loss Percent
Total NC Retail	38,091,457	39,749,335	1,657,878	4.35%
Total SC Retail	6,774,668	7,050,281	275,613	4.07%
All other jurisdications	17,324,584	17,648,803	324,219	1.87%
Total System	62,190,710	64,448,420	2,257,710	3.63%
Allocation percent - NC retail	61.25%	61.68%		

Line Loss Calculations for Normalized Test Period Sales	MWh @ Meter	MWh @ Prod Out.	Losses (MWh)	Loss Percent
Total NC Retail	37,695,769	39,336,426	1,640,656	4.35%
Total SC Retail	6,372,042	6,631,275	259,233	4.07%
All other jurisdications	17,959,446	18,295,546	336,100	1.87%
Total System	62,027,257	64,263,247	2,235,990	3.60%
Allocation percent - NC retail	60.77%	61.21%		

I/A

DUKE ENERGY PROGRESS, LLC
Annual Fuel and Fuel Related Expense
Derivation of Equal Percent Increases for all Rate Classes
Annualized Revenues at Current Rates
Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Harrington Workpaper 11

Revenue Class (1)	Annual Sales (2) per RMC28	Annual EE Opt-Out Sales (3) per RMCRY14E	Annual DSM Opt-Out Sales (4) per RMCRY14E	Annual Customer Count (5) per RMC28	Annual Rider JAA kWh Units (6) per RMC28	Annual Rider JAA Demand Units (7) per PMC34	Annual Customer Count (Adjusted for Premise Billing) (8) = (5) adjusted by RMCRY10	Annual Revenues (9) per RMC28	Remove Partial Year Impacts: Test Year Rate Changes** (10) - See Annualization Adjustment Worksheet	Remove Partial Year Impacts: Opt-Out Credit Due to Jan 2019 EE Rate (11) per RMCRY14	Remove Partial Year Impacts: Opt-Out Credit Due to Jan. 2019 DSM Rate (12) per RMCRY15	Remove Partial Year Impacts: NC Rate Case - Mar. 16, 2018 (13) per Report PMCM74 Worksheet	Remove Partial Year Impacts: REPS Revenue Due to December 2018 Rate Change (14) per RMCRY19	Annual Revenues Excluding All Rate Adjustments (15)=(9)-(10-11-12)-(13)-(14)	Add Impact of Approved Rate Changes During Test Year: Annual Impact of Rate Changes*** (16) See Annualization Adjustment worksheet	Add Impact of Approved Rate Changes During Test Year: Annual Opt-Out Impact of 1/19 EE Rate (17) = (3) * Rate Change	Add Impact of Approved Rate Changes During Test Year: Annual Opt-Out Impact of 1/19 EE Rate (18) = (4) * Rate Change	Add Impact of Approved Rate Changes During Test Year: NC Rate Case - Mar. 16, 2018 (19) per Report PMCM74 Worksheet	Add Impact of Approved Rate Changes During Test Year: Annual Impact of Dec. 2018 REPS Rate (20) = (8) * Rate Change	Annual Revenue At Current Rates (21)=(15)+(16-17-18)+(19)+(20)
Residential	18,212,932,855	0	0	14,714,829	18,212,832,853	0	14,626,840	$1,847,498,050	$48,436,176	$0	$0	$38,029,191	$3,814,551	$1,888,016,130	$107,022,665	$0	$0	$101,952,080	$12,720,131	$1,920,711,005
Residential	18,146,992,624	0	0	14,619,905	18,146,992,624	0	14,538,187	$1,825,812,649	$48,751,421	$0	$0	$36,632,056	$3,564,532	$1,876,832,658	$106,418,618	$0	$0	$102,580,341	$12,648,273	$1,898,487,940
SGS	-2,556	0	0	8	-2,556	0	0	-$225	$1	$0	$0	($21)	$0	-$218	($4)	$0	$0	($12)	$0	-$235
MGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	($18)	$18	$0	$0	$0	$0	$0	$18
LGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Lighting	65,942,887	0	0	115,015	65,942,887	0	82,853	$21,683,606	$83,753	$0	$0	($602,855)	$20,037	$22,183,670	$606,054	$0	$0	($628,251)	$71,906	$22,223,382
Commercial	12,342,849,189	3,872,513,312	4,057,417,628	2,463,488	2,201,284,432	30,452,436	3,353,921	$1,328,688,837	$54,875,236	$1,452,372	$24,887	$11,409,890	$1,035,922	[illegible]	$120,802,685	$9,476,103	$161,817	$35,295,813	$3,614,063	$1,368,380,850
Residential	1,202	0	0	16	1,202	0	0	$222	$7	$0	$0	$10	$4	$178	$11	$0	$0	$10	$0	$200
SGS	1,835,230,084	18,684,073	17,157,586	1,830,421	1,835,230,084	0	1,808,956	$231,791,855	$10,223,866	$7,189	$127	$20,824,534	$785,854	$208,850,818	$22,780,740	$28,708	$686	$11,391,572	$2,765,798	$246,867,882
MGS	8,061,438,382	2,825,998,190	2,830,307,408	436,324	51,841,437	14,184,425	393,029	$744,873,521	$47,085,727	$1,082,331	$18,470	$21,865,730	$173,334	$676,798,431	$91,701,933	$4,725,876	$117,212	$22,896,158	$605,764	$785,252,686
LGS	1,132,008,792	1,118,154,703	1,097,955,335	2,115	0	2,268,083	877	$84,286,732	$1,089,315	$382,806	$6,290	$2,593,161	$377	$80,984,235	$4,352,574	$2,861,308	$43,918	$2,907,187	$1,350	$85,350,198
Lighting	214,108,729	11,476,168	11,997,321	15,713	214,108,729	0	130,438	$48,817,527	$261,271	($115)	$0	($1,887,545)	$66,349	$50,282,836	$1,967,427	($489)	$0	($1,793,043)	$211,675	$50,689,543
Industrial	8,008,590,835	8,086,451,880	8,119,913,879	41,674	85,054,487	18,564,476	22,101	$521,583,186	$18,549,304	$3,043,278	$31,854	$18,961,157	$52,439	$491,052,719	$43,890,438	$19,225,430	$124,449	$17,795,532	$319,580	$511,501,881
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGS	18,175,804	4,859,845	4,940,856	12,301	18,175,804	0	8,422	$2,081,181	$103,319	$3,742	$84	$27,088	$14,757	$1,868,814	$226,643	$21,087	$358	$102,163	$48,486	$2,228,660
MGS	2,045,888,405	1,541,179,827	1,546,028,304	26,872	454,833	5,918,516	7,751	$157,739,843	$10,497,086	$584,511	$8,872	$4,317,932	$32,518	$143,286,758	$20,795,139	$3,066,008	$62,841	$4,798,847	$112,084	$165,281,110
LGS	5,928,521,898	6,528,082,158	6,556,260,806	2,308	0	12,645,862	6,617	$359,106,806	$3,848,351	$2,455,108	$41,419	$12,447,465	$39,297	$343,187,786	$22,710,841	$15,514,816	$262,250	$13,001,392	$139,055	$363,239,828
Lighting	15,021,730	3,329,849	4,682,791	195	15,021,730	0	1,311	$2,652,757	$17,636	($42)	$0	($88,148)	$5,867	$2,778,321	$137,876	($500)	$0	($104,870)	$18,955	$2,760,781
Public Streets & Highways	62,665,816	0	0	11,027	62,665,816	0	10,198	$16,694,211	$94,074	$0	$0	($2,321)	$4,275	$16,598,184	$588,281	$0	$0	($2,454)	$15,706	$17,199,713
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGS	4,353,685	0	0	5,445	4,353,685	0	5,362	$415,867	$22,438	$0	$0	$19,311	$1,172	$352,047	$52,309	$0	$0	$41,619	$4,258	$454,133
MGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Lighting	58,312,131	0	0	5,582	58,312,131	0	4,836	$16,278,244	$71,637	$0	$0	($41,632)	$3,103	$16,246,137	$536,072	$0	$0	($44,077)	$7,647	$16,745,580
Military	1,418,748,802	1,324,087,345	1,324,087,345	48	1,920	5,396,213	38	$84,990,339	$1,211,871	$501,636	$4,421	$3,146,323	$176	$81,141,365	$5,434,801	$1,827,325	$80,963	$3,285,960	$364	$86,154,319
Residential	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
MGS	0	0	0	0	0	0	0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LGS	1,416,748,882	1,324,087,345	1,324,087,345	48	0	5,396,213	38	$84,990,125	$1,211,868	$501,636	$4,421	$3,146,331	$176	$81,141,146	$5,434,804	$1,827,325	$80,963	$3,285,868	$364	$86,154,290
Lighting	1,920	0	0	0	1,920	0	0	$214	$2	$0	$0	($4)	$0	$220	$18	$0	$0	($9)	$0	$229
NC Retail	38,045,807,677	13,382,852,368	13,701,418,852	17,251,177	18,511,958,610	52,413,189	17,008,480	$3,580,430,623	$125,383,810	$4,998,774	$64,863	$148,548,441	$4,747,363	$3,325,834,398	$277,718,991	$32,278,863	$347,330	$158,328,926	$16,680,085	$3,725,734,287

Rate Schedules (excludes REPS)

Revenue Class (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
RES (includes RES-RTOU)	15,865,019,184	0	0	14,343,037	15,865,019,184	0	0	$1,778,815,316	$37,345,804	$0	$0	$34,180,360	$3,584,533	$1,843,838,810	$81,778,275	$0	$0	$0	$0	$1,725,418,835
SGS	1,918,181,840	25,544,018	28,088,424	1,940,215	1,918,181,840	0	0	$229,390,523	$10,153,219	$11,131	$191	$11,682,202	$774,405	$198,815,019	$22,620,238	$60,785	$1,044	$0	$0	$219,373,416
MGS	2,723,184,988	310,330,189	314,365,982	197,026	0	12,841,955	0	$277,614,804	$11,832,137	$125,680	$2,122	$14,660,873	$105,808	$224,077,795	$28,628,025	$786,186	$13,371	$0	$0	$249,804,261
SGS-TOU	8,307,422,449	4,030,048,706	4,135,186,379	236,886	0	21,198,805	0	$631,397,177	$43,387,020	$1,318,588	$28,194	$37,232,358	$128,987	$583,293,825	$85,183,821	$9,991,516	$165,408	$0	$0	$637,700,522
LGS	3,127,891,905	3,242,257,424	3,165,863,605	1,075	0	2,311,774	0	$58,748,559	$1,106,015	$424,882	$7,284	$20,824,087	$2,552	$67,145,835	$4,347,647	$2,718,573	$48,639	$0	$0	$68,828,331
LGS-TOU	1,597,061,416	1,678,824,388	1,684,177,807	2,432	0	3,017,270	0	$114,895,733	$2,671,218	$618,652	$10,372	$3,579,455	$2,121	$110,342,168	$8,155,348	$3,898,321	$66,567	$0	$0	$112,432,928
LGS-RTP	10,614,788	10,614,788	10,614,788	13	0	40,147	0	$809,543	$40,280	$4,370	$77	$31,821	$0	$792,079	$234,760	$25,283	$425	$0	$0	$1,021,151
LGS-RTP-TOU	5,748,609,461	8,338,490,606	8,336,490,606	849	0	12,940,737	0	$323,841,329	$5,891,824	$2,272,134	$38,187	$11,964,593	$2,771	$306,768,481	$21,740,204	$15,080,848	$253,480	$0	$0	$315,174,356
LGS Class	8,479,277,570	8,168,267,416	9,172,206,806	3,488	0	18,310,256	0	$528,383,163	$4,249,837	$3,340,048	$56,130	$28,171,956	$7,445	$487,148,804	$32,488,159	$21,822,904	$367,081	$0	$0	$497,438,768

Rate Class

Revenue Class (1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
Residential	18,148,893,828	0	0	14,619,821	18,148,983,828	0	14,538,187	$1,825,812,873	$48,751,428	$0	$0	$38,632,067	$3,594,539	$1,876,832,838	$106,418,630	$0	$0	$102,590,852	$12,648,273	$1,898,488,040
SGS	1,958,757,097	25,544,016	28,098,424	2,023,182	1,958,757,097	0	2,817,343	$234,288,778	$10,354,432	$11,131	$191	$10,880,922	$812,783	$212,171,883	$23,058,584	$40,785	$1,044	$11,535,293	$2,843,539	$249,548,540
MGS	13,207,868,767	4,387,178,017	4,478,138,719	485,086	52,798,290	34,102,831	400,780	$902,413,463	$57,502,813	$1,645,742	$28,341	$28,203,662	$205,834	$820,085,237	$112,407,072	$10,383,844	$178,053	$27,387,325	$717,348	$960,513,826
LGS	8,478,277,570	9,170,324,216	9,178,323,826	3,480	0	18,310,258	10,332	$528,383,163	$8,149,337	$3,340,048	$56,130	$18,188,978	$38,850	$505,323,177	$32,488,159	$21,823,172	$367,232	$18,904,527	$140,980	$534,744,328
Lighting	353,410,397	19,806,113	22,660,112	134,363	353,410,397	0	239,228	$89,332,348	$433,788	($287)	$0	($2,437,164)	$96,356	$91,441,183	$3,247,547	($1,168)	$0	($2,582,348)	$329,886	$92,438,556
	38,045,807,677	13,382,852,368	13,701,418,852	17,251,177	18,511,958,610	52,413,189	17,008,480	$3,580,430,623	$125,383,810	$4,998,774	$64,863	$148,548,441	$4,747,363	$3,325,834,398	$277,718,991	$32,278,863	$347,330	$158,328,926	$36,680,085	$3,725,734,287

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Actual MWH Sales by Jurisdiction - Subject to Weather
Twelve Months Ended March 31, 2018
Docket No. E-2, Sub 1204

Harrington Workpaper 12

Line No.	Description	Reference	North Carolina	South Carolina	Retail Total Company	% NC	% SC
1	Residential	Company Records	16,212,941	2,124,879	18,337,820	88.41	11.59
2	Commercial	Company Records	12,343,207	1,695,832	14,039,039	87.92	12.08
3	Industrial	Company Records	8,008,994	2,530,292	10,539,285	75.99	24.01
4	Other Public Authority	Company Records	1,418,749	49,526	1,468,275	96.63	3.37
5	Total Retail Sales subject to weather	Sum 1 through 4	37,983,890	6,400,529	44,384,420		
6	Lighting	Company Records	62,686	14,427	77,113		
7	Total Retail Sales	Line 5 + Line 6	38,046,576	6,414,956	44,461,533		

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Production Plant Allocation Factors
Cost of Service Study ending December 31, 2018
Docket No. E-2, Sub 1204

Harrington Workpaper 13

Total Production Plant	System	NC Retail	Residential	Small GS	Med GS	Lrg GS	Ltg
Rate Base	16,654,620,260.27	10,159,449,637.14	5,038,986,361.77	625,383,836.37	2,870,205,385.50	1,624,134,063.08	739,990.43
NC Retail % to Total System		61.00%	30.26%	3.76%	17.23%	9.75%	0.00%
Allocation of Classes to Total NC Retail		100.00%	49.60%	6.16%	28.25%	15.99%	0.01%

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Adjustment - MWh
Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Description	Reference	Total Company MWh	NC RETAIL % To Total	NC RETAIL MWh	SC RETAIL % To Total	SC RETAIL MWh
	Residential						
1	Residential		(277,134)	88.41	(245,014)	11.59	(32,120)
	Commercial						
2	Small and Medium General Service		(177,800)	87.92	(156,322)	12.08	(21,478)
	Industrial						
3	Large General Service		(129,569)	75.99	(98,460)	24.01	(31,110)
	OPA						
4	Other Public Authority (Large General Service)		(12,950)	96.63	(12,514)	3.37	(436)
5	Total Retail	L1+ L2+ L3 + L4	(597,454)		(512,310)		(85,144)
6	Wholesale		(273,277)				
7	Total Company	L5 + L6	(870,731)		(512,310)		(85,144)

Note: Totals may not sum due to rounding

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Weather Adjustment - MWh
Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

		Residential MWH Adjustment	Commercial MWH Adjustment	Industrial MWH Adjustment	Other Public Authority MWH Adjustment	Total Retail MWH Adjustment	Wholesale MWH Adjustment
April	2018	(103,408)	-	(35,282)	-	(138,690)	(1,563)
May	2018	(28,053)	(8,585)	(17,810)	-	(54,447)	(33,684)
June	2018	(185,737)	(86,887)	(21,885)	(5,782)	(300,291)	(198,952)
July	2018	(92,102)	(33,697)	(106,078)	(3,424)	(235,301)	(79,798)
August	2018	24,133	10,823	5,669	1,191	41,816	20,525
September	2018	(127,205)	31,171	101,925	(8,189)	(2,297)	(79,728)
October	2018	(221,055)	(123,169)	(110,300)	(860)	(455,384)	(122,663)
November	2018	(8,362)	(130,560)	(58,350)	(6,178)	(203,451)	(10,818)
December	2018	(101,677)	130,283	96,047	-	124,653	(62,059)
January	2019	224,778	29,898	16,496	842	272,014	164,657
February	2019	77,988	2,922	-	1,051	81,962	90,461
March	2019	263,564	-	-	8,399	271,963	40,344
12ME March	2019	(277,134)	(177,800)	(129,569)	(12,950)	(597,454)	(273,277)

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Scenario Differences
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 15

Exhibit 2 Schedule 1: Line Loss

Line Losses	Exh 2 Sch 1 Pg 1 Ln 16	(1,817,527)
Generation	Exh 2 Sch 1 Pg 1 Ln 10	63,957,400
	%	-2.842%
	Multiplier	1.028418

Schedule 2: Proposed Nuclear Capacity Factor & Normalized Sales

Normalized Sales	Exh 4, Total Co., Ln 4	61,992,467
Sales Forecast	Exh 2 Sch 1 Pg 1 Ln 18	62,155,919
Difference		(163,452)
Gross up for losses		(168,097)
MWh changes in Coal		(168,097)
MWH changes in Losses		4,645

		Before Adj	Adj	Total
Total Coal MWh	WP 3	11,131,286	(168,097)	10,963,189
Total Losses MWh		(1,817,527)	4,645	(1,812,882)

		Before Adj	After Adj	Adjustment
Total Coal $	WP 4	348,993,723	343,723,461	(5,270,262)

Schedule 3: NERC 5 year average Capacity Factor & Projected Sales

		Nuclear-MWHs	Nuclear Costs
Nuclear	WP 1-Nuclear	29,713,145	$ 183,324,690
Nuclear - NERC Average	WP 2-Nuclear NERC	28,826,864	$ 177,856,495
	Adjustment	(886,281)	$ (5,468,195)

		Coal	Coal Costs	
Coal MWh	WP 3	11,131,286	$ 348,993,723	
Adjustment from Above	above	886,281	$ 27,787,143	(Priced at the avg Coal $/MWH)
		12,017,568	$ 376,780,866	

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 16

Line No.	Description	Forecast $	EMF (Over)/Under Collection $	Total $
1	Amount in current docket	$ 280,994,289	$ 82,823,475	$ 363,817,764
2	Amount in 2018 Filing: Docket E-2 Sub 1173	310,910,776	78,097,747	389,008,523
3	Reduction in prior year docket in excess of 2.5%	(57,234,383)		(57,234,383)
4	Increase/(Decrease)	$ 27,317,896	$ 4,725,727	$ 32,043,624
5	2.5% of 2018 NC revenue of $3,587,884,326			89,697,108
6	Amount over 2.5%			0

		System Cost	Alloc %	NC Alloc. Forecast
WP 4	Purchases	$ 14,160,859	61.66%	$ 8,731,585
WP 4	Purchases for REPS Compliance	168,625,939	61.66%	103,974,754
WP 4	Purchases for REPS Compliance Capacity	34,622,728	61.00%	21,120,137
WP 4	Purchases from Qualifying Facilities Energy	193,990,299	61.66%	119,614,418
WP 4	Purchases from Qualifying Facilities Capacity	39,793,114	61.00%	24,274,113
WP 4	Allocated Economic Purchases	5,318,328	61.66%	3,279,281
	Total	$ 456,511,266		$ 280,994,289

		System Cost	Alloc %	NC Alloc. Forecast
Prior Year	Purchases	$ 71,395,237	60.59%	$ 43,258,374
Prior Year	Purchases for REPS Compliance	187,595,597	60.59%	113,664,172
Prior Year	Purchases for REPS Compliance Capacity	38,515,117	60.52%	23,309,349
Prior Year	Purchases from Qualifying Facilities Energy	162,649,793	60.59%	98,549,509
Prior Year	Purchases from Qualifying Facilities Capacity	33,362,793	60.52%	20,191,162
Prior Year	Allocated Economic Purchases	19,703,265	60.59%	11,938,208
	Total	$ 513,221,803		$ 310,910,776

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test - Normalized
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Harrington Workpaper 16a

Line No.	Description		Forecast $		EMF (Over)/Under Collection $		Total $
1	Amount in current docket	$	277,604,760	$	82,823,475	$	360,428,234
2	Amount in 2018 Filing: Docket E-2 Sub 1173		309,190,377		78,097,747		387,288,125
3	Reduction in prior year docket in excess of 2.5%		(54,730,355)				(54,730,355)
4	Increase/(Decrease)	$	23,144,738	$	4,725,727	$	27,870,465
5	2.5% of 2018 NC revenue of $3,587,884,326						89,697,108
6	Amount over 2.5%						0

			System Cost	Alloc %		NC Alloc. Forecast
WP 4	Purchases	$	14,160,859	60.77%	$	8,605,966
WP 4	Purchases for REPS Compliance		168,625,939	60.77%		102,478,890
WP 4	Purchases for REPS Compliance Capacity		34,622,728	61.00%		21,120,137
WP 4	Purchases from Qualifying Facilities Energy		193,990,299	60.77%		117,893,550
WP 4	Purchases from Qualifying Facilities Capacity		39,793,114	61.00%		24,274,113
WP 4	Allocated Economic Purchases		5,318,328	60.77%		3,232,103
	Total	$	456,511,266		$	277,604,760

			System Cost	Alloc %		NC Alloc. Forecast
Prior Year	Purchases	$	71,395,237	60.20%	$	42,980,069
Prior Year	Purchases for REPS Compliance		187,595,597	60.20%		112,932,908
Prior Year	Purchases for REPS Compliance Capacity		38,515,117	60.52%		23,309,349
Prior Year	Purchases from Qualifying Facilities Energy		162,649,793	60.20%		97,915,486
Prior Year	Purchases from Qualifying Facilities Capacity		33,362,793	60.52%		20,191,162
Prior Year	Allocated Economic Purchases		19,703,265	60.20%		11,861,403
	Total	$	513,221,803		$	309,190,377

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test-Detail Calculation
Test Period April 2018 - March 2019
Docket No. E-2, Sub 1204

Harrington Workpaper 15b

Line No.		Reference	Apr'18	May'18	Jun'18	July'18	Aug'18
1	System kWh Sales, at generation		4,636,855,673	4,790,246,098	5,856,645,043	6,359,201,366	6,396,519,871
2	NC Retail kWh Sales, at generation		2,922,608,924	2,841,868,501	3,501,325,638	3,819,890,072	3,838,942,450
3	NC Retail % of Sales	Line 2 / Line 1	63.03%	59.33%	59.78%	60.07%	60.02%
	Total Purchase Power, Excl. JDA						
4	System Purchase Power, Excl. JDA		$ 30,903,462	$ 37,042,584	$ 36,347,253	$ 48,228,217	$ 43,182,460
5	NC Purchase Power	Line 4 * Line 3	$ 19,478,452	$ 21,975,883	$ 21,729,842	$ 28,970,207	$ 25,916,355
6	NC Retail kWh Sales		2,821,409,876	2,743,728,563	3,379,526,908	3,687,026,670	3,705,569,376
7	Incurred Rate	Line 5 / Line 6 * 100	0.690	0.801	0.643	0.786	0.699
	Total Capacity						
8	System Capacity		$ 5,782,707	$ 5,674,828	$ 9,101,624	$ 9,523,762	$ 9,397,062
9	NC Capacity	Capacity*.6052	$ 3,499,694	$ 3,434,406	$ 5,508,309	$ 5,763,781	$ 5,687,102
10	NC Retail kWh Sales	Line 6	2,821,409,876	2,743,728,563	3,379,526,908	3,687,026,670	3,705,569,376
11	Incurred Rate	Line 9/Line 10*100	0.124	0.125	0.163	0.156	0.153
12	Total Incurred Rate	Line 7 + Line 11	0.814	0.926	0.806	0.942	0.853
13	Billed Rate	Billed Rates Below	0.461	0.461	0.461	0.461	0.461
14	(Over)/Under cents per kwh	Line 13 - Line 12	0.353	0.465	0.345	0.481	0.392
15	(Over)/Under $	Line 14 * Line10 /100	9,966,974	12,757,351	11,653,168	17,730,950	14,514,938

Line No.	Sept'18	Oct'18	Nov'18	Dec'18	Jan'19	Feb'19	Mar'19	12ME
1	5,600,434,066	5,314,903,250	4,874,260,445	4,981,394,129	5,794,466,810	5,252,024,407	4,699,033,969	64,555,985,928
2	3,444,193,130	3,364,015,670	3,009,697,941	2,956,160,111	3,465,598,155	3,357,151,243	2,894,649,756	39,416,093,589
3	61.50%	63.29%	61.75%	59.34%	59.81%	63.92%	61.60%	61.06%
4	$ 51,035,291	$ 32,621,404	$ 34,293,760	$ 17,654,479	$ 21,940,974	$ 25,169,675	$ 23,859,381	$ 402,278,939
5	$ 31,386,194	$ 20,647,392	$ 21,175,368	$ 10,476,874	$ 13,122,677	$ 16,088,708	$ 14,697,618	$ 245,665,399
6	3,324,420,103	3,247,433,903	2,905,623,408	2,853,151,529	3,344,812,989	3,239,878,500	2,793,993,421	38,046,575,246
7	0.944	0.636	0.729	0.367	0.392	0.497	0.528	0.646
8	$ 9,555,756	$ 2,508,522	$ 3,801,068	$ 2,050,191	$ 4,238,370	$ 5,182,042	$ 4,345,958	$ 71,161,889
9	$ 5,783,144	$ 1,518,157	$ 2,300,406	$ 1,240,775	$ 2,565,062	$ 3,136,172	$ 2,630,174	$ 43,067,175
10	3,324,420,103	3,247,433,903	2,905,623,408	2,853,151,529	3,344,812,989	3,139,878,500	2,793,993,421	38,046,575,246
11	0.174	0.047	0.079	0.043	0.077	0.097	0.094	0.113
12	1.118	0.683	0.808	0.411	0.469	0.593	0.620	0.759
13	0.461	0.461	0.461	0.588	0.747	0.747	0.747	
14	0.657	0.221	0.347	(0.177)	(0.278)	(0.154)	(0.127)	
15	21,838,490	7,189,730	10,076,244	(5,048,825)	(9,311,212)	(4,989,889)	(3,554,444)	82,823,475

Billed Rate from Docket E-2, Sub 1146 - Apr'18-Nov'18

Line No.			
16	Purchases (Other Purchases + Economic Purchases)	60,888,103	2017 Ward WP 4
17	MWH Sales	68,022,851	2017 Ward WP 3
18	Billed Rate for Purchases	0.090	
19	Renewables	154,215,192	2017 Ward WP 4
20	MWH Sales	68,022,851	2017 Ward WP 3
21	Billed Rate for Renewables	0.227	
22	QF Purchases	55,113,822	2017 Ward WP 4
23	MWH Sales	68,022,851	2017 Ward WP 3
24	Billed Rate for Renewables	0.081	
25	Capacity (REPS and QF)	43,476,066	2017 Ward WP 4
26	MWH Sales	68,022,851	2017 Ward WP 3
27	Billed Rate for Capacity	0.064	
28	Total Billed Rate	0.461	

Billed Rate from Docket E-2, Sub 1173 - Dec'18-Mar'19

Purchases (Other Purchases + Economic Purchases)	91,098,502	2018 Ward WP 4
MWH Sales	68,667,857	2018 Ward WP 3
Billed Rate for Purchases	0.133	
Renewables	187,595,597	2018 Ward WP 4
MWH Sales	68,667,857	2018 Ward WP 3
Billed Rate for Renewables	0.273	
QF Purchases (energy)	162,649,793	2018 Ward WP 4
MWH Sales	68,667,857	2018 Ward WP 3
Billed Rate for Renewables	0.237	
Capacity (REPS and QF)	71,877,910	2018 Ward WP 4
MWH Sales	68,667,857	2018 Ward WP 3
Billed Rate for Capacity	0.105	
Total Billed Rate	0.747	

*** December billed Rate is based on prorated billing factors**

	Prior Bill Rate (Sub 1146)	New Bill Rate (Sub 1173)	December Blended Rate
Approved Rates	0.461	0.747	
Ratios of Days to rate	55.81%	44.19%	
Prorated Rate	0.257	0.330	0.588

**** January billed Rate is based on prorated billing factors**

	Prior Bill Rate (Sub 1146)	New Bill Rate (Sub 1173)	January Blended Rate
Approved Rates	0.461	0.747	
Ratios of Days to rate	0.001%	99.999%	
Prorated Rate	0.000	0.747	0.747

I/A

Revised Harrington Exhibit 1

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Summary Comparison of Fuel and Fuel-Related Cost Factors
Test Period Twelve Months Ended March 31, 2019
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Description	Reference	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
	Current Fuel and Fuel-Related Cost Factors (Approved Fuel Rider Docket No. E-2, Sub 1173)						
1	Approved Fuel and Fuel-Related Costs Factors	Input	2.311	2.556	2.477	1.757	2.251
2	EMF Increment / (Decrement)	Input	0.575	0.363	0.343	1.038	0.885
3	EMF Interest Decrement cents/kWh, if applicable	n/a	-	-	-	-	-
4	Approved Net Fuel and Fuel-Related Costs Factors	Sum	2.886	2.919	2.820	2.795	3.136
	Other Fuel and Fuel-Related Cost Factors						
5	NERC Capacity Factor of 91.8% with Projected Billing Period MWh Sales	Exh 2 Sch 3 pg 3	2.781	2.795	2.738	2.743	2.918
6	Proposed Nuclear Capacity Factor of 94.62% with Normalized Test Period MWh Sales	Exh 2 Sch 2 pg 3	2.736	2.756	2.711	2.714	2.806
	Proposed Fuel and Fuel Related Cost Factors using Proposed Nuclear Capacity Factor of 94.62% with Projected Billing Period MWh Sales						
7	Fuel and Fuel-Related Costs excluding Purchased Capacity cents/kWh	Exh 2 Sch 1 pg 2	2.206	2.372	2.345	1.977	2.280
8	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Exh 2 Sch 1 pg 2	0.138	0.155	0.123	0.079	0.001
9	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Sum	2.344	2.527	2.468	2.056	2.281
10	EMF Increment/(Decrement) cents/kWh	Exh 2 Sch 1 pg 2	0.394	0.217	0.236	0.666	0.548
11	EMF Interest Decrement cents/kWh, if applicable	n/a	-	-	-	-	-
12	Net Proposed Fuel and Fuel-Related Costs Factors cents/kWh	Exh 2 Sch 1 pg 2	2.738	2.744	2.704	2.722	2.829

Note: The above rates do not include state regulatory fees.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.62% with Normalized Test Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Description		Residential	General Service Small	General Service Medium	General Service Large	Lighting	Total
1	NC Normalized Test Period MWh Sales	Workpaper 8a	16,022,203	1,941,728	11,007,307	8,368,542	353,965	37,693,746
	Calculation of Renewable and Qualifying Facilities Purchased Power Capacity Rate by Class							Amount
2	Renewable Purchased Power Capacity	Workpaper 4						$ 34,622,728
3	Purchases from Qualifying Facilities Capacity	Workpaper 4						39,793,114
4	Total of Renewable and Qualifying Facilities Purchased Power Capacity	Line 2 + Line 3						$ 74,415,842
5	NC Portion - Jurisdictional % based on Production Plant Allocator	Input						61.00%
6	NC Renewable and Qualifying Facilities Purchased Power Capacity	Line 5 * Line 6						$ 45,394,250
7	Production Plant Allocation Factors	Workpaper 13	49.599%	6.156%	28.252%	15.986%	0.007%	100.000%
8	Renewable and Qualifying Facilities Purchased Power Capacity allocated on Production Plant %	Line 6 * Line 7	$ 22,515,098	$ 2,794,328	$ 12,824,594	$ 7,256,923	$ 3,306	$ 45,394,250
9	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh based on Projected Billing Period Sales	Line 8 / Line 1 / 10	0.141	0.144	0.117	0.087	0.001	0.120
	Summary of Total Rate by Class		cents/KWh	cents/KWh	cents/KWh	cents/KWh	cents/KWh	
10	Fuel and Fuel-Related Costs excluding Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 15 - Line 11 - Line 13 - Line 14	2.201	2.395	2.358	1.961	2.257	
11	Renewable and Qualifying Facilities Purchased Power Capacity cents/kWh	Line 9	0.141	0.144	0.117	0.087	0.001	
12	Total adjusted Fuel and Fuel-Related Costs cents/kWh	Line 10 + Line 11	2.342	2.539	2.475	2.048	2.258	
13	EMF Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	0.394	0.217	0.236	0.666	0.548	
14	EMF Interest Increment/(Decrement) cents/kWh	Exh 3 pg 2, 3, 4, 5, 6	-	-	-	-	-	
15	Net Fuel and Fuel-Related Costs Factors cents/kWh	Exh 2 Sch 2 Page 3	2.736	2.756	2.711	2.714	2.806	

Note: Rounding differences may occur

I/A

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 94.62% and Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Rate Class	Projected Billing Period MWh Sales		Annual Revenue at Current rates		Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease) cents/kwh	Current Total Fuel Rate (including renewables and EMF) E-2, Sub 1173 cents/kwh	Proposed Total Fuel Rate (including renewables and EMF) cents /kwh
		A		B		C	D	E	F	G
		Workpaper 8		Workpaper 11		Line 27 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Exhibit 1, Line 4	E + F = G
1	Residential	16,265,079	$	1,898,488,040	$	(24,068,291)	-1.3%	(0.148)	2.886	2.738
2	Small General Service	1,806,876		249,548,540		(3,163,679)	-1.3%	(0.175)	2.919	2.744
3	Medium General Service	10,414,506		950,513,824		(12,050,244)	-1.3%	(0.116)	2.820	2.704
4	Large General Service	9,223,825		534,744,328		(6,779,280)	-1.3%	(0.073)	2.795	2.722
5	Lighting	381,171		92,439,556		(1,171,913)	-1.3%	(0.307)	3.136	2.829
6	NC Retail	38,091,457	$	3,725,734,287	$	(47,233,407)				

Line No.	Description	Source		Amount
	Total Proposed Composite Fuel Rate:			
7	Adjusted System Total Fuel Costs	Workpaper 8	$	1,433,036,845
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2	-	74,415,842
9	Adjusted System Other Fuel Costs	Line 7 - Line 8	$	1,358,621,003
10	NC Retail Allocation % - sales at generation	Workpaper 10		61.68%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$	837,997,435
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 1, Page 2		45,394,250
13	NC Retail Total Fuel Costs before 2.5% Purchase Power Test	Line 11 + Line 12	$	883,391,685
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16		0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$	883,391,685
16	NC Projected Billing Period MWh Sales	Line 6, col A		38,091,457
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 / 10		2.319
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1		0.401
19	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1		0.000
20	Total Proposed Composite Fuel Rate	Sum of Lines 17-19		2.720
	Total Current Composite Fuel Rate - Docket E-2 Sub 1173:			
21	Current composite Fuel Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 17		2.242
22	Current composite EMF Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 18		0.602
23	Current composite EMF interest cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 19		0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21-23		2.844
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24		(0.124)
26	NC Projected Billing Period MWh Sales	Line 6, col A		38,091,457
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10	$	(47,233,407)

Notes:
Rounding differences may occur
Includes 100% ownership of all generating resources

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
Proposed Nuclear Capacity Factor of 94.62% with Normalized Test Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Rate Class	Normalized Test Period MWh Sales		Annual Revenue at Current rates		Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease) cents/kwh	Current Total Fuel Rate (including renewables and EMF) E-2, Sub 1173 cents/kwh	Proposed Total Fuel Rate (including renewables and EMF) cents/kwh
		A		B		C	D	E	F	G
		Workpaper 8a		Workpaper 11		Line 27 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Exhibit 1, Line 4	E + F = G
1	Residential	16,022,203	$	1,898,488,040	$	(24,009,068)	-1.3%	(0.150)	2.886	2.736
2	Small General Service	1,941,728		249,548,540		(3,155,894)	-1.3%	(0.163)	2.919	2.756
3	Medium General Service	11,007,307		950,513,824		(12,020,592)	-1.3%	(0.109)	2.820	2.711
4	Large General Service	8,368,542		534,744,328		(6,762,599)	-1.3%	(0.081)	2.795	2.714
5	Lighting	353,965		92,439,556		(1,169,029)	-1.3%	(0.330)	3.136	2.806
6	NC Retail	37,693,746	$	3,725,734,287	$	(47,117,182)				

Line No.	Description	Source		Amount
	Total Proposed Composite Fuel Rate:			
7	Adjusted System Total Fuel Costs	Workpaper 8a	$	1,427,700,085
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2		74,415,842
9	System Other Fuel Costs	Line 7 - Line 8	$	1,353,284,242
10	NC Retail Allocation % - sales at generation	Workpaper 10		61.21%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$	828,345,285
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 2, Page 2		45,394,250
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$	873,739,535
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16a		0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$	873,739,535
16	Adjusted NC Normalized Test Period MWh Sales	Line 6, col A		37,693,746
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 /10		2.318
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1		0.401
19	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1		0.000
20	Total Proposed Composite Fuel Rate	Sum of Lines 17-19		2.719
	Total Current Composite Fuel Rate - Docket E-2 Sub 1173:			
21	Current composite Fuel Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 17		2.242
22	Current composite EMF Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 18		0.602
23	Current composite EMF Interest cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 19		0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21 - 23		2.844
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24		(0.125)
26	Adjusted NC Normalized Test Period MWh Sales	Line 6, col A		37,693,746
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10	$	(47,117,182)

Note: Rounding differences may occur

I/A

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Uniform Percentage Average Bill Adjustment by Customer Class
NERC Capacity Factor of 91.8% with Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Rate Class	Projected Billing Period MWh Sales	Annual Revenue at Current rates	Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease) cents/kwh	Current Total Fuel Rate (including renewables and EMF) E-2, Sub 1173 cents/kwh	Proposed Total Fuel Rate (including renewables and EMF) cents /kwh
		A	B	C	D	E	F	G
		Workpaper 8	Workpaper 11	Line 27 as a % of Column B	C / B	If D=0 then 0 if not then (C*100)/(A*1000)	Exhibit 1, Line 4	E + F = H
1	Residential	16,265,079	$ 1,898,488,040	$ (17,080,722.69)	-0.9%	(0.105)	2.886	2.781
2	Small General Service	1,806,876	249,548,540	(2,245,191)	-0.9%	(0.124)	2.919	2.795
3	Medium General Service	10,414,506	950,513,824	(8,551,786)	-0.9%	(0.082)	2.820	2.738
4	Large General Service	9,223,825	534,744,328	(4,811,102)	-0.9%	(0.052)	2.795	2.743
5	Lighting	381,171	92,439,556	(831,680)	-0.9%	(0.218)	3.136	2.918
6	NC Retail	38,091,457	$ 3,725,734,287	$ (33,520,482)				

Line No.	Description	Source	Amount
	Total Proposed Composite Fuel Rate:		
7	Adjusted System Total Fuel Costs	Workpaper 8b	$ 1,455,355,794
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	74,415,842
9	System Other Fuel Costs	Line 7 - Line 8	$ 1,380,939,952
10	NC Retail Allocation % - sales at generation	Workpaper 10	61.68%
11	NC Retail Other Fuel Costs	Line 9 * Line 10	$ 851,763,762
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Exhibit 2 Sch 3, Page 2	45,394,250
13	NC Retail Total Fuel Costs	Line 11 + Line 12	$ 897,158,012
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16	0
15	NC Retail Total Fuel Costs	Line 13 + Line 14	$ 897,158,012
16	NC Projected Billing Period MWh Sales	Line 6, col A	38,091,457
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 /10	2.355
18	Proposed Composite EMF Rate cents/kWh	Exhibit 3 Page 1	0.401
19	Proposed Composite EMF Rate Interest cents/kWh	Exhibit 3 Page 1	0.000
20	Total Proposed Composite Fuel Rate	Sum of Lines 15-17	2.756
	Total Current Composite Fuel Rate - Docket E-2 Sub 1173:		
21	Current composite Fuel Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 17	2.242
22	Current composite EMF Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 18	0.602
23	Current composite EMF Interest cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 19	0.000
24	Total Current Composite Fuel Rate	Sum of Lines 21 - 23	2.844
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24	(0.088)
26	NC Projected Billing Period MWh Sales	Line 6, col A	38,091,457
27	Increase/(Decrease) in Fuel Costs	Line 25* Line 26 * 10	$ (33,520,482)

Note: Rounding differences may occur

I/A

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Calculation of Fuel and Fuel Related Cost Factors Using:
Proposed Nuclear Capacity Factor of 94.62% with Normalized Test Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Revised Harrington Exhibit 2
Schedule 2
Page 1 of 3

Line No.	Unit	Reference	Generation (MWh) A	Unit Cost (cents/KWh) C/A/10=B	Fuel Cost ($) C
1	Total Nuclear	Workpaper 3-4	29,713,146	0.6170	$ 183,324,690
2	Coal	Workpaper 15	10,961,068	3.1353	343,656,962
3	Gas - CT and CC	Workpaper 3-4	22,185,181	2.6683	591,960,856
4	Reagents & Byproducts	Workpaper 4	-		26,265,057
5	Total Fossil	Sum of Lines 2 - 4	33,146,249		961,882,875
6	Hydro	Workpaper 3	648,112		
7	Net Pumped Storage		-		
8	Total Hydro	Sum of Lines 6 - 7	648,112		
9	Utility Owned Solar Generation	Workpaper 3	279,675		
10	Total Generation	Line 1 + Line 5 + Line 8 + Line 9	63,787,182		1,145,207,565
11	Purchases	Workpaper 3 - 4	7,560,370		464,368,032
12	JDA Savings Shared	Workpaper 5	-		(21,960,626)
13	Total Purchases	Sum of Lines 11 - 12	7,560,370		442,407,406
14	Total Generation and Purchases	Line 10 + Line 13	71,347,552		1,587,614,971
15	Fuel expense recovered through intersystem sales	Workpaper 3 - 4	(7,544,324)		(161,032,005)
16	Line losses and Company use	Line 18 - Line 15 - Line 14	(1,812,824)		
17	System Fuel Expense for Fuel Factor	Lines 14 + Line 15 + Line 16			$ 1,426,582,966
18	Normalized Test Period MWh Sales for Fuel Factor	Exhibit 4	61,990,405		61,990,405
19	Fuel and Fuel-Related Costs cents/kWh	Line 17 / Line 18 / 10			2.301

Note: Rounding differences may occur

I/A

Revised Harrington Exhibit 4

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel-Related Expense
Normalized Test Period MWh Sales, Fuel and Fuel-Related Revenue, Fuel and Fuel-Related Expense, and System Peak
Test Period Twelve Months Ended March 31, 2019
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Line No.	Description	Reference	Total Company	North Carolina Retail	North Carolina Residential	North Carolina Small General Service	North Carolina Medium General Service	North Carolina Large General Service	North Carolina Lighting
1	Test Period MWh Sales	Workpaper 8a	62,568,164	38,046,575	16,147,005	1,958,731	11,108,152	8,479,278	353,410
2	Customer Growth MWh Adjustment	Workpaper 8a	292,971	159,480	120,212	3,258	35,216	238	555
3	Weather MWh Adjustment	Workpaper 8a	(870,731)	(512,310)	(245,014)	(20,261)	(136,061)	(110,973)	-
4	Total Adjusted MWh Sales	Sum Lines 1-3	61,990,405	37,693,746	16,022,203	1,941,728	11,007,307	8,368,542	353,965
5	Test Period Fuel and Fuel-Related Revenue *		$ 1,748,320,962	$ 1,060,762,739					
6	Test Period Fuel and Fuel-Related Expense *		$ 2,066,739,723	$ 1,249,044,489					
7	Test Period Unadjusted (Over)/Under Recovery	Line 5 - Line 6	$ 318,418,761	$ 188,281,750					

Line No.	Description	2018 Winter Coincidental Peak (CP) KW
8	Total System Peak	15,022,364
9	NC Retail	8,952,091
10	NC Residential Peak	5,755,959
11	NC Small General Service	536,770
12	NC Medium General Service	1,812,628
13	NC Large General Service	846,735

Notes:

* Total Company Fuel and Fuel-Related Revenue and Fuel and Fuel-Related Expense are quantifed based on NC Retail's knowi share of revenues and expenses grossed up to also include the percentage of sales not belonging to NC Retail.

Rounding differences may occur.

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Normalized Sales
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Revised Harrington Workpaper 8a

		Test Period Sales MWhs	Weather Normalization	Customer Growth	Remove impact of SC DERP Net Metered Generation	Adjusted Projected Sales (MWhs)
NC						
	Residential	16,147,005	(245,014)	120,212		16,022,203
	Small General Service	1,958,731	(20,261)	3,258		1,941,728
	Medium General Service	11,108,152	(136,061)	35,216		11,007,307
	Large General Service	8,479,278	(110,973)	238		8,368,542
	Lighting	353,410	0	555		353,965
Total		38,046,575	(512,310)	159,480		37,693,746
SC Retail		6,414,956	(85,144)	7,439	34,790	6,372,041
Total Wholesale		18,106,633	(273,277)	126,052		17,959,408
Total Adjusted NC System Sales		62,568,164	(870,731)	292,971	34,790	62,025,195

	Test Period	Adjusted Projected
NC as a percentage of total	60.81%	60.77%
SC as a percentage of total	10.25%	10.27%
Wholesale as a percentage of total	28.94%	28.96%

SC Net Metering allocation adjustment

Total Projected SC NEM MWhs		34,790	
Marginal Fuel rate per MWh for SC NEM	$	32.11	
Fuel Benefit to be directly assigned to SC	$	1,117,119	
System Fuel Expense	$	1,426,582,966	Exh 2 Sch 2 Pg 1
Fuel benefit to be directly assigned to SC Retail		1,117,119	
Total Adjusted System Fuel Expense	$	1,427,700,085	Exh 2 Sch 2 Pg 3

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Customer Growth Adjustment - MWh
Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Revised Harrington Workpaper 9

Rate Schedule	Reference	NC Proposed MWH [1] Adjustment	SC Proposed MWH Adjustment	Wholesale Proposed MWH Adjustment
Residential	RES	120,212	7,813	
General:				
General Service Small	SGS	3,258	(2,492)	
General Service Medium	MGS	35,216	2,162	
Total General		38,474	(330)	
Lighting:				
Street Lighting	SLS/SLR	417	11	
Sports Field Lighting	SFLS	95	(6)	
Traffic Signal Service	TSS/TFS	42	(50)	
Total Street Lighting		555	(44)	
Industrial:				
I - Textile	LGS	-	-	
I - Nontextile	LGS	238	-	
Total Industrial		238	-	
Total		159,480	7,439	126,052

[1] Using the regression method (Residential, Lighting, SGS classes) and a customer by customer method for MGS and Industrial.

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
Scenario Differences
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Revised Harrington Workpaper 15 I/A

Exhibit 2 Schedule 1: Line Loss

Line Losses	Exh 2 Sch 1 Pg 1 Ln 16	(1,817,527)
Generation	Exh 2 Sch 1 Pg 1 Ln 10	63,957,400
	%	-2.842%
	Multiplier	1.028418

Schedule 2: Proposed Nuclear Capacity Factor & Normalized Sales

Normalized Sales	Exh 4, Total Co., Ln 4	61,990,405
Sales Forecast	Exh 2 Sch 1 Pg 1 Ln 18	62,155,919
Difference		(165,514)
Gross up for losses		(170,218)
MWh changes in Coal		(170,218)
MWH changes in Losses		4,704

		Before Adj	Adj	Total
Total Coal MWh	WP 3	11,131,286	(170,218)	10,961,068
Total Losses MWh		(1,817,527)	4,704	(1,812,823)

		Before Adj	After Adj	Adjustment
Total Coal $	WP 4	348,993,723	343,656,962	(5,336,761)

Schedule 3: NERC 5 year average Capacity Factor & Projected Sales

		Nuclear-MWHs		Nuclear Costs
Nuclear	WP 1-Nuclear	29,713,145	$	183,324,690
Nuclear - NERC Average	WP 2-Nuclear NERC	28,826,864	$	177,856,495
	Adjustment	(886,281)	$	(5,468,195)

		Coal		Coal Costs	
Coal MWh	WP 3	11,131,286	$	348,993,723	
Adjustment from Above	above	886,281	$	27,787,143	(Priced at the avg Coal $/MWH)
		12,017,568	$	376,780,866	

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Revised Harrington Workpaper 16

I/A

Line No.	Description	Forecast $	EMF (Over)/Under Collection $	Total $
1	Amount in current docket	$ 281,070,708	$ 98,879,127	$ 379,949,835
2	Amount in 2018 Filing: Docket E-2 Sub 1173	310,910,776	78,097,747	389,008,523
3	Reduction in prior year docket in excess of 2.5%	(57,234,383)		(57,234,383)
4	Increase/(Decrease)	$ 27,394,316	$ 20,781,380	$ 48,175,695
5	2.5% of 2018 NC revenue of $3,587,884,326			89,697,108
6	Amount over 2.5%			0

		System Cost	Alloc %	NC Alloc. Forecast
WP 4	Purchases	$ 14,160,859	61.68%	$ 8,734,418
WP 4	Purchases for REPS Compliance	168,625,939	61.68%	104,008,479
WP 4	Purchases for REPS Compliance Capacity	34,622,728	61.00%	21,120,137
WP 4	Purchases from Qualifying Facilities Energy	193,990,299	61.68%	119,653,216
WP 4	Purchases from Qualifying Facilities Capacity	39,793,114	61.00%	24,274,113
WP 4	Allocated Economic Purchases	5,318,328	61.68%	3,280,345
	Total	$ 456,511,266		$ 281,070,708

		System Cost	Alloc %	NC Alloc. Forecast
Prior Year	Purchases	$ 71,395,237	60.59%	$ 43,258,374
Prior Year	Purchases for REPS Compliance	187,595,597	60.59%	113,664,172
Prior Year	Purchases for REPS Compliance Capacity	38,515,117	60.52%	23,309,349
Prior Year	Purchases from Qualifying Facilities Energy	162,649,793	60.59%	98,549,509
Prior Year	Purchases from Qualifying Facilities Capacity	33,362,793	60.52%	20,191,162
Prior Year	Allocated Economic Purchases	19,703,265	60.59%	11,938,208
	Total	$ 513,221,803		$ 310,910,776

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test - Normalized
Billing Period December 1, 2019 - November 30, 2020
Docket No. E-2, Sub 1204

Revised Harrington Workpaper 16a

Line No.	Description	Forecast $	EMF (Over)/Under Collection $	Total $
1	Amount in current docket	$ 277,600,013	$ 98,879,127	$ 376,479,140
2	Amount in 2018 Filing: Docket E-2 Sub 1173	309,190,377	78,097,747	387,288,125
3	Reduction in prior year docket in excess of 2.5%	(54,730,355)		(54,730,355)
4	Increase/(Decrease)	$ 23,139,991	$ 20,781,380	$ 43,921,371
5	2.5% of 2018 NC revenue of $3,587,884,326			89,697,108
6	Amount over 2.5%			0

		System Cost	Alloc %	NC Alloc. Forecast
WP 4	Purchases	$ 14,160,859	60.77%	$ 8,605,790
WP 4	Purchases for REPS Compliance	168,625,939	60.77%	102,476,796
WP 4	Purchases for REPS Compliance Capacity	34,622,728	61.00%	21,120,137
WP 4	Purchases from Qualifying Facilities Energy	193,990,299	60.77%	117,891,140
WP 4	Purchases from Qualifying Facilities Capacity	39,793,114	61.00%	24,274,113
WP 4	Allocated Economic Purchases	5,318,328	60.77%	3,232,037
	Total	$ 456,511,266		$ 277,600,013

		System Cost	Alloc %	NC Alloc. Forecast
Prior Year	Purchases	$ 71,395,237	60.20%	$ 42,980,069
Prior Year	Purchases for REPS Compliance	187,595,597	60.20%	112,932,908
Prior Year	Purchases for REPS Compliance Capacity	38,515,117	60.52%	23,309,349
Prior Year	Purchases from Qualifying Facilities Energy	162,649,793	60.20%	97,915,486
Prior Year	Purchases from Qualifying Facilities Capacity	33,362,793	60.52%	20,191,162
Prior Year	Allocated Economic Purchases	19,703,265	60.20%	11,861,403
	Total	$ 513,221,803		$ 309,190,377

I/A

DUKE ENERGY PROGRESS, LLC
North Carolina Annual Fuel and Fuel Related Expense
2.5% Calculation Test - Detail Calculation
Test Period April 2018 - March 2019
Docket No. E-2, Sub 1204

Revised Harrington Workpaper 16b

Line No.		Reference	Apr'18	May'18	Jun'18	July'18	Aug'18	Sept'18	Oct'18	Nov'18	Dec'18	Jan'19	Feb'19	Mar'19	Apr19	May19	Jun19	15ME
1	System kWh Sales, at generation		4,636,856,473	4,790,246,098	5,856,645,043	6,359,201,366	6,396,519,871	5,600,434,066	5,314,903,250	4,874,260,445	4,981,394,129	5,794,466,810	5,252,024,407	4,699,033,969	4,552,563,478	5,036,544,467	5,524,085,729	79,669,179,602
2	NC Retail kWh Sales, at generation		2,922,606,924	2,841,868,501	3,501,325,638	3,819,890,072	3,838,942,450	3,444,193,130	3,364,015,670	3,009,697,941	2,956,160,111	3,465,598,155	3,357,151,243	2,894,643,756	2,841,301,317	2,950,169,419	3,347,286,069	48,554,850,394
3	NC Retail % of Sales	Line 2 / Line 1	63.03%	59.33%	59.78%	60.07%	60.02%	61.50%	63.29%	61.75%	59.34%	59.81%	63.92%	61.60%	62.41%	58.58%	60.59%	60.95%
	Total Purchase Power, Excl. JDA																	
4	System Purchase Power, Excl. JDA		$ 30,903,462	$ 37,042,584	$ 36,347,253	$ 48,228,217	$ 43,182,460	$ 51,035,291	$ 32,621,404	$ 34,293,760	$ 17,654,479	$ 21,940,974	$ 25,169,675	$ 23,859,381	$ 37,155,563	$ 36,682,605	$ 39,194,737	$ 515,311,845
5	NC Purchase Power	Line 4 * Line 3	$ 19,478,452	$ 21,975,883	$ 21,729,842	$ 28,970,207	$ 25,916,385	$ 31,384,194	$ 20,647,392	$ 21,175,368	$ 10,476,874	$ 13,122,677	$ 16,088,708	$ 14,697,618	$ 23,189,166	$ 21,488,934	$ 23,749,812	$ 314,091,512
6	NC Retail kWh Sales		2,821,409,876	2,743,728,563	3,379,526,908	3,687,026,670	3,705,569,376	3,324,420,103	3,247,433,903	2,905,623,408	2,853,151,529	3,344,812,989	3,239,878,500	2,793,993,421	2,728,574,094	2,833,194,484	3,213,527,076	46,821,870,900
7	Incurred Rate	Line 5 / Line 6 * 100	0.690	0.801	0.643	0.786	0.699	0.944	0.636	0.729	0.367	0.392	0.497	0.526	0.850	0.758	0.739	0.671
	Total Capacity																	
8	System Capacity		$ 5,782,707	$ 5,674,828	$ 9,101,624	$ 9,523,762	$ 9,397,062	$ 9,555,756	$ 2,508,322	$ 3,801,068	$ 2,050,191	$ 4,238,370	$ 5,182,042	$ 4,345,958	$ 6,120,873	$ 7,384,605	$ 8,159,863	$ 92,827,230
9	NC Capacity	Capacity*.6052	$ 3,499,694	$ 3,434,408	$ 5,508,303	$ 5,763,781	$ 5,687,102	$ 5,783,144	$ 1,518,157	$ 2,300,406	$ 1,240,775	$ 2,565,062	$ 3,136,172	$ 2,630,174	$ 3,733,794	$ 4,504,683	$ 4,977,598	$ 56,283,250
10	NC Retail kWh Sales	Line 6	2,821,409,876	2,743,728,563	3,379,526,908	3,687,026,670	3,705,569,376	3,324,420,103	3,247,433,903	2,905,623,408	2,853,151,529	3,344,812,989	3,239,878,500	2,793,993,421	2,728,574,094	2,833,194,484	3,213,527,076	46,821,870,900
11	Incurred Rate	Line 9/Line 10*100	0.124	0.125	0.163	0.156	0.153	0.174	0.047	0.079	0.043	0.077	0.097	0.094	0.137	0.159	0.155	0.120
12	Total Incurred Rate	Line 7 + Line 11	0.814	0.926	0.806	0.942	0.853	1.118	0.683	0.808	0.411	0.469	0.593	0.620	0.987	0.917	0.894	0.791
13	Billed Rate	Billed Rates Below	0.461	0.461	0.461	0.463	0.461	0.461	0.461	0.461	0.589	0.747	0.747	0.747	0.747	0.747	0.747	
14	(Over)/Under cents per kwh	Line 13 - Line 12	0.353	0.465	0.345	0.481	0.392	0.657	0.221	0.347	(0.177)	(0.278)	(0.154)	(0.127)	0.239	0.170	0.147	
15	(Over)/Under $	Line 14 * Line10 /100	9,968,974	12,757,351	11,653,168	17,730,950	14,514,938	21,838,490	7,189,730	10,076,244	(5,048,825)	(9,311,212)	(4,989,889)	(3,554,444)	6,529,667	4,816,394	4,709,591	98,879,127

Billed Rate from Docket E-2, Sub 1146 - Apr'18-Nov'18

16	Purchases (Other Purchases + Economic Purchases)	60,888,103	2017 Ward WP 4
17	MWH Sales	68,022,851	2017 Ward WP 3
18	Billed Rate for Purchases	0.090	
19	Renewables	154,215,192	2017 Ward WP 4
20	MWH Sales	68,022,851	2017 Ward WP 3
21	Billed Rate for Renewables	0.227	
22	QF Purchases	55,113,822	2017 Ward WP 4
23	MWH Sales	68,022,851	2017 Ward WP 3
24	Billed Rate for Renewables	0.081	
25	Capacity (REPS and QF)	43,476,066	2017 Ward WP 4
26	MWH Sales	68,022,851	2017 Ward WP 3
27	Billed Rate for Capacity	0.064	
28	Total Billed Rate	0.461	

Billed Rate from Docket E-2, Sub 1173 - Dec'18-Mar'19

Purchases (Other Purchases + Economic Purchases)	91,098,502	2018 Ward WP 4
MWH Sales	68,667,857	2018 Ward WP 3
Billed Rate for Purchases	0.133	
Renewables	187,595,597	2018 Ward WP 4
MWH Sales	68,667,857	2018 Ward WP 3
Billed Rate for Renewables	0.273	
QF Purchases (energy)	162,649,793	2018 Ward WP 4
MWH Sales	68,667,857	2018 Ward WP 3
Billed Rate for Renewables	0.237	
Capacity (REPS and QF)	71,877,910	2018 Ward WP 4
MWH Sales	68,667,857	2018 Ward WP 3
Billed Rate for Capacity	0.105	
Total Billed Rate	0.747	

* December billed Rate is based on prorated billing factors

	Prior Bill Rate (Sub 1146)	New Bill Rate (Sub 1173)	December Blended Rate
Approved Rates	0.461	0.747	
Ratios of Days to rate	55.81%	44.19%	
Prorated Rate	0.257	0.330	0.588

** January billed Rate is based on prorated billing factors

	Prior Bill Rate (Sub 1146)	New Bill Rate (Sub 1173)	January Blended Rate
Approved Rates	0.461	0.747	
Ratios of Days to rate	0.001%	99.999%	
Prorated Rate	0.000	0.747	0.747

I/A

Revised Harrington Exhibit 3
Page 1 of 6

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Proposed Composite
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.515	2.280	2,821,410	$ 6,616,553	-	$ 6,616,553
2	May	2.794	2.286	2,743,729	13,930,507	-	13,930,507
3	June	2.884	2.277	3,379,527	20,501,107	-	20,501,107
4	July	2.641	2.275	3,687,027	13,504,786	-	13,504,786
5	August	2.619	2.277	3,705,569	12,651,306	-	12,651,306
6	September	2.954	2.276	3,324,420	22,555,310	-	22,555,310
7	October	2.142	2.282	3,247,434	(4,537,212)	-	(4,537,212)
8	November	2.768	2.286	2,905,623	14,008,619	-	14,008,619
9	December (New Rates - Sub 1173)	4.223	2.256	2,853,152	56,124,620	-	56,124,620
10	January 2019	2.845	2.250	3,344,813	19,890,481	$ (33,252)	19,857,229
11	February	0.978	2.256	3,239,879	(41,422,510)	-	(41,422,510)
12	March	2.714	2.248	2,793,993	13,007,082	-	13,007,082
13	Total Test Period			38,046,575	146,830,650	(33,252)	146,797,398
14	April	2.686	2.236	2,728,574	12,291,799	-	12,291,799
15	May	2.782	2.239	2,833,194	15,364,636	-	15,364,636
16	June	2.680	2.249	3,213,527	13,827,917	-	13,827,917
17	Total 15-month Test Period			46,821,871	$ 188,315,002	$ (33,252)	$ 188,281,750
18	Booked 15-month (Over) / Under Recovery						$ 188,281,750
19	Coal inventory Rider (Over) / Under Recovery						257,250
20	Adjustment to remove by-product net gain/loss accrued expense						(44,144,639)
21	Adjustment to include by-product net gain/loss cash payments						6,640,945
22	Total 15-month (Over) / Under Recovery						$ 151,035,306
23	Normalized Test Period MWh Sales	Exhibit 4					37,693,746
24	Experience Modification Increment / (Decrement) cents/KWh						0.401

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Residential
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.501	2.179	1,138,012	$ 3,660,529		$ 3,660,529
2	May	3.023	2.179	1,016,135	8,577,706		8,577,706
3	June	2.787	2.179	1,404,775	8,539,907		8,539,907
4	July	2.467	2.179	1,586,631	4,574,733		4,574,733
5	August	2.510	2.179	1,553,969	5,138,198		5,138,198
6	September	2.811	2.179	1,404,365	8,874,465		8,874,465
7	October	2.193	2.179	1,264,650	179,201		179,201
8	November	2.995	2.179	1,072,132	8,748,809		8,748,809
9	December (New Rates - Sub 1173)	3.604	2.237	1,386,673	18,956,228		18,956,228
10	January 2019	2.682	2.311	1,552,025	5,751,516	$ (14,440)	5,737,076
11	February	0.899	2.311	1,553,478	(21,931,387)		(21,931,387)
12	March	2.733	2.311	1,214,159	5,128,001		5,128,001
13	Total Test Period			16,147,005	56,197,905	(14,440)	56,183,465
14	April	3.033	2.311	1,060,985	7,664,663		7,664,663
15	May	3.295	2.311	1,051,096	10,340,265		10,340,265
16	June	2.843	2.311	1,331,074	7,081,848		7,081,848
17	Total 15-month Test Period			19,590,161	$ 81,284,681	$ (14,440)	$ 81,270,241
18	Booked 15-month (Over) / Under Recovery						$ 81,270,241
19	Coal inventory Rider (Over) / Under Recovery						107,665
20	Adjustment to remove by-product net gain/loss accrued expense						(21,280,626)
21	Adjustment to include by-product net gain/loss cash payments						3,041,510
22	Total 15-month (Over) / Under Recovery						$ 63,138,790
23	Normalized Test Period MWh Sales	Exhibit 4					16,022,203
24	Experience Modification Increment (Decrement) cents/KWh						0.394

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Small General Service
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.289	2.121	140,607	$ 236,079		$ 236,079
2	May	2.535	2.121	136,871	567,097		567,097
3	June	2.480	2.121	178,846	642,201		642,201
4	July	2.281	2.121	194,597	310,810		310,810
5	August	2.231	2.121	198,191	217,119		217,119
6	September	2.489	2.121	179,772	662,100		662,100
7	October	1.789	2.121	174,119	(578,233)		(578,233)
8	November	2.312	2.121	156,234	298,658		298,658
9	December (New Rates - Sub 1173)	4.862	2.313	120,842	3,080,272		3,080,272
10	January 2019	2.969	2.556	174,110	718,822	$ (1,763)	717,059
11	February	1.095	2.556	159,655	(2,332,952)		(2,332,952)
12	March	2.847	2.556	144,886	421,865		421,865
13	Total Test Period			1,958,731	4,243,838	(1,763)	4,242,075
14	April	2.930	2.556	136,059	508,889		508,889
15	May	2.974	2.556	144,225	603,324		603,324
16	June	2.793	2.556	167,849	397,399		397,399
17	Total 15-month Test Period			2,406,864	$ 5,753,449	$ (1,763)	$ 5,751,686
18	Booked 15-month (Over) / Under Recovery						$ 5,751,686
19	Coal inventory Rider (Over) / Under Recovery						13,266
20	Adjustment to remove by-product net gain/loss accrued expense						(1,888,719)
21	Adjustment to include by-product net gain/loss cash payments						333,054
22	Total 15-month (Over) / Under Recovery						$ 4,209,287
23	Normalized Test Period MWh Sales	Exhibit 4					1,941,728
24	Experience Modification Increment (Decrement) cents/KWh						0.217

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Medium General Service
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month		Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)		2.440	2.356	834,634	$ 700,759		$ 700,759
2	May		2.524	2.356	871,652	1,468,210		1,468,210
3	June		2.683	2.356	1,042,496	3,411,985		3,411,985
4	July		2.601	2.356	1,074,969	2,629,373		2,629,373
5	August		2.536	2.356	1,098,143	1,980,830		1,980,830
6	September		2.852	2.356	988,512	4,902,428		4,902,428
7	October		1.955	2.356	1,021,065	(4,091,099)		(4,091,099)
8	November		2.453	2.356	940,892	913,230		913,230
9	December (New Rates - Sub 1173)		5.035	2.409	706,334	18,544,231		18,544,231
10	January 2019		3.287	2.477	883,889	7,155,890	$ (9,828)	7,146,062
11	February		1.127	2.477	855,202	(11,548,986)		(11,548,986)
12	March		2.927	2.477	790,364	3,557,351		3,557,351
13	Total Test Period				11,108,152	29,624,202	(9,828)	29,614,374
14	April		2.697	2.477	827,811	1,817,211		1,817,211
15	May		2.639	2.477	908,898	1,474,141		1,474,141
16	June		2.710	2.477	967,184	2,251,604		2,251,604
17	Total 15-month Test Period				13,812,044	$ 35,167,158	$ (9,828)	$ 35,157,330
18	Booked 15-month (Over) / Under Recovery							$ 35,157,330
19	Coal inventory Rider (Over) / Under Recovery							75,961
20	Adjustment to remove by-product net gain/loss accrued expense							(11,042,950)
21	Adjustment to include by-product net gain/loss cash payments							1,830,267
22	Total 15-month (Over) / Under Recovery							$ 26,020,608
23	Normalized Test Period MWh Sales	Exhibit 4						11,007,307
24	Experience Modification Increment (Decrement) cents/KWh							0.236

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Large General Service
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month		Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)		2.709	2.417	678,418	$ 1,978,810		$ 1,978,810
2	May		2.886	2.417	689,394	3,230,432		3,230,432
3	June		3.476	2.417	723,936	7,668,586		7,668,586
4	July		3.135	2.417	801,315	5,754,642		5,754,642
5	August		3.034	2.417	825,198	5,091,306		5,091,306
6	September		3.504	2.417	723,070	7,861,222		7,861,222
7	October		2.406	2.417	757,387	(84,221)		(84,221)
8	November		2.971	2.417	707,153	3,914,585		3,914,585
9	December (New Rates - Sub 1173)		4.582	2.125	610,753	15,002,143		15,002,143
10	January 2019		2.603	1.757	704,241	5,960,860	$ (7,072)	5,953,788
11	February		0.937	1.757	643,138	(5,275,468)		(5,275,468)
12	March		2.371	1.757	615,274	3,776,307		3,776,307
13	Total Test Period				8,479,278	54,879,204	(7,072)	54,872,132
14	April		2.086	1.757	674,418	2,215,935		2,215,935
15	May		2.160	1.757	699,442	2,816,304		2,816,304
16	June		2.297	1.757	718,601	3,877,285		3,877,285
17	Total 15-month Test Period				10,571,739	$ 63,788,728	$ (7,072)	$ 63,781,656
18	Booked 15-month (Over) / Under Recovery							$ 63,781,656
19	Coal Inventory Rider (Over) / Under Recovery							57,952
20	Adjustment to remove by-product net gain/loss accrued expense							(9,490,349)
21	Adjustment to include by-product net gain/loss cash payments							1,376,227
22	Total 15-month (Over) / Under Recovery							$ 55,725,485
23	Normalized Test Period MWh Sales	Exhibit 4						8,368,542
24	Experience Modification Increment (Decrement) cents/KWh							0.666

Notes:
Totals may not foot due to rounding.

Duke Energy Progress, LLC
North Carolina Annual Fuel and Fuel Related Expense
Calculation of Experience Modification Factor - Lighting
Test Period Twelve Months Ended March 31, 2019
Docket No. E-2, Sub 1204

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	1.793	1.657	29,739	$ 40,376	-	$ 40,376
2	May	1.950	1.657	29,677	87,063		87,063
3	June	2.466	1.657	29,473	238,428		238,428
4	July	2.454	1.657	29,516	235,228		235,228
5	August	2.401	1.657	30,068	223,853		223,853
6	September	2.546	1.657	28,700	255,094		255,094
7	October	1.780	1.657	30,213	37,141		37,141
8	November	2.113	1.657	29,213	133,338		133,338
9	December (New Rates - Sub 1173)	3.817	1.919	28,549	541,747		541,747
10	January 2019	3.244	2.251	30,547	303,393	$ (149)	303,244
11	February	1.076	2.251	28,406	(333,718)		(333,718)
12	March	2.673	2.251	29,310	123,557		123,557
13	Total Test Period			353,410	1,885,501	(149)	1,885,352
14	April	2.541	2.251	29,301	85,101		85,101
15	May	2.693	2.251	29,533	130,603		130,603
16	June	3.014	2.251	28,819	219,780		219,780
17	Total 15-month Test Period			441,063	$ 2,320,986	$ (149)	$ 2,320,837
18	Booked 15-month (Over) / Under Recovery						$ 2,320,837
19	Coal inventory Rider (Over) / Under Recovery						2,406
20	Adjustment to remove by-product net gain/loss accrued expense						(441,994)
21	Adjustment to include by-product net gain/loss cash payments						59,886
22	Total (Over) / Under Recovery						$ 1,941,135
23	Normalized Test Period MWh Sales	Exhibit 4					353,965
24	Experience Modification Increment (Decrement) cents/KWh						0.548

Notes:
Totals may not foot due to rounding.

FPWC Harrington Cross Ex. 3

1A

STATE OF NORTH CAROLINA

PERSON COUNTY

IN THE GENERAL COURT OF JUSTICE
SUPERIOR COURT DIVISION
17 CVS 395

CERTAINTEED GYPSUM NC, INC.,

Plaintiff,

v.

DUKE ENERGY PROGRESS, LLC,

Defendant.

OPINION & FINAL JUDGMENT

1. THIS MATTER came on for trial without a jury before the undersigned commencing on July 9, 2018. The Court now issues its Opinion & Final Judgment.

Brooks, Pierce, McLendon, Humphrey, & Leonard, LLP by Jim W. Phillips, Jr., Brian C. Fork, and Kimberly M. Marston, for Plaintiff.

Smith, Anderson, Blount, Dorsett, Mitchell & Jernigan, LLP by Donald H. Tucker, Jr. and Isaac A. Linnartz, for Defendant.

Gale, Judge.

I. INTRODUCTION

2. This litigation involves disputes between Plaintiff CertainTeed Gypsum NC, Inc. ("CTG"), a wallboard manufacturer, and Defendant Duke Energy Progress, LLC ("DEP"), a public utility that operates plants to produce electricity, arising from their Second Amended and Restated Supply Agreement ("2012 Agreement"), regarding supply and acceptance of synthetic gypsum, a byproduct of coal-fired electric power plants and a raw material used to manufacture wallboard. The parties define the synthetic gypsum that meets the contractual specifications as "Gypsum Filter Cake."

3. CTG and DEP first entered into a supply agreement in 2004 ("2004 Agreement"). At that time, DEP was planning to install flue gas desulfurization systems that would produce synthetic gypsum at its coal-fired plants in Roxboro, North Carolina ("Roxboro Plant") and Mayo, North Carolina ("Mayo Plant"), and CTG was seeking to build its first wallboard-manufacturing plant in the Southeast United States. CTG and DEP executed the Amended and Restated Supply Agreement in 2008 ("2008 Agreement") following CTG's decision to delay construction of its plant because of the 2008 economic downturn commonly referred to as the "Great Recession." The parties executed the 2012 Agreement when CTG was constructing its plant. The Court may refer to the 2004 Agreement, the 2008 Agreement, and the 2012 Agreement collectively as the "Supply Agreements."

4. A drop in natural gas prices has required DEP to decrease utilization of its coal-fired plants, resulting in its decreased production of synthetic gypsum. This decreased production has resulted in a dispute as to the quantity term of the 2012 Agreement, which has led to other disputes as to the terms and obligations of the 2012 Agreement.

5. The parties' disputes fall within four principal categories. The parties disagree: (1) as to the Minimum Monthly Quantity ("MMQ"), of Gypsum Filter Cake that DEP is required to supply and CTG is required to accept, including whether Gypsum Filter Cake means only synthetic gypsum produced at DEP's Roxboro Plant and Mayo Plant; (2) whether DEP has met its contractual obligation to use "commercially reasonable efforts" to maintain a stockpile ("Stockpile") of 250,000 net

dry tons of Gypsum Filter Cake and to furnish a replenishment plan ("Replenishment Plan") now that the Stockpile has fallen below that volume; (3) whether DEP is now excused from its contractual obligations because its performance is inconsistent with its primary purpose as a regulated public utility ("Primary Purpose"); and (4) if DEP's performance is not excused, whether CTG will be limited to an exclusive optional remedy of terminating the 2012 Agreement and recovering liquidated damages if DEP discontinues its supply obligation as defined by the 2012 Agreement.

II. PROCEDURAL HISTORY

6. CTG initiated this action on June 30, 2017, by filing a Complaint, which sought only a declaratory judgment of the quantity term in the 2012 Agreement. (*See* Compl., ECF No. 19.)

7. On August 11, 2017, DEP filed its Notice of Designation As Mandatory Complex Business Case under N.C. Gen. Stat. § 7A-45.4. (ECF No. 6.) On August 11, 2017, this matter was designated as a mandatory complex business case by the Chief Justice. (ECF No. 1.) On August 14, 2017, the matter was assigned to the undersigned. (ECF No. 2.)

8. On August 24, 2017, CTG moved for summary judgment prior to the close of the pleadings, contending that it was entitled to its requested declaration as a matter of law based on the clear contract language of the 2012 Agreement. (ECF No. 11.)

9. On September 21, 2017, the Court heard argument on Plaintiff's Motion for Summary Judgment. On September 28, 2017, the Court provided an informal

oral ruling that it would deny Plaintiff's Motion for Summary Judgment because it found the relevant contract provisions to be ambiguous, requiring the Court to consider extrinsic evidence to determine the intent of the parties.

10. The parties proceeded with expedited discovery. The Court has noted that the parties have consistently acted in an exemplary and professional manner to move forward to an early trial and have only sought court intervention when their manifest good-faith efforts were able to narrow but not fully resolve disputes as to the scope or timing of discovery. Their conduct throughout the litigation is a clear example of the highest standards of professionalism to which trial lawyers should aspire.

11. On January 29, 2018, with leave of the Court, CTG filed its Amended Complaint to expand its request for declaratory judgment and seek additional relief, including compensatory damages, specific performance, and attorneys' fees and costs. (ECF No. 53.) CTG now asks the Court to declare that:

a. DEP is required to supply the MMQ of 50,000 Net Dry Tons of Gypsum Filter Cake for the entire term of the 2012 Agreement, subject to minor fluctuations permitted under Section 3.1;

b. DEP's supply obligation is not limited to Gypsum Filter Cake produced at its Roxboro Plant and Mayo Plant, and, as necessary, DEP may be required to obtain Gypsum Filter Cake from alternative sources at its own expense;

c. DEP is contractually obligated to use commercially reasonable efforts to maintain the Stockpile at 250,000 net dry tons of Gypsum Filter Cake and that the Replenishment Plan DEP prepared based on DEP's improper interpretation of the MMQ did not meet its contractual obligation; and

d. CTG continues to have the election to pursue specific performance rather than termination in the event DEP takes actions that would trigger the optional termination remedy.

(*See* Am. Compl. ¶¶ 71, 128.)

12. When filing its Amended Complaint on January 29, 2018, CTG also moved for a preliminary injunction. The Court was not required to hear this motion after being advised that the parties had reached an interim agreement, and the Court provided an expedited peremptory trial date.

13. On March 16, 2018, DEP filed its Answer to Plaintiff's Amended Complaint and Counterclaim, to which it later added a request for attorneys' fees and costs. (*See* ECF No. 91.) DEP asks the Court to declare that:

a. DEP's supply obligation is limited to Gypsum Filter Cake produced at its Roxboro Plant and Mayo Plant even if that production is less than the contractual MMQ, (Countercl. ¶ 25, ECF No. 124);

b. DEP is now excused from any supply obligation because its continued supply of Gypsum Filter Cake is inconsistent with its

Primary Purpose as a regulated public utility, (Countercl. ¶ 25); and

c. If DEP's supply obligation is not otherwise excused, the remedy of termination with the recovery of liquidated damages pursuant to Section 6.3 of the 2012 Agreement becomes CTG's exclusive remedy once DEP takes a contractually-defined action that triggers that section. (Countercl. ¶ 32.)

14. On May 9, 2018, DEP moved for partial judgment on the pleadings as to its request that the Court declare that CTG would be limited to an exclusive remedy once the termination remedy of Section 6.3 of the 2012 Agreement is triggered. After briefing, the Court orally advised the parties that it would reserve its consideration of this issue until trial.

15. On June 26, 2018, the Court issued an order incorporating its prior oral rulings on Plaintiff's Motion for Summary Judgment and Defendant's Motion for Partial Judgment on the Pleadings. (ECF No. 115.)

16. The parties waived their rights to a jury trial and consented to a trial held outside the county of origin. The trial commenced on July 9, 2018, at the North Carolina Business Court, 201 North Greene Street, Greensboro, North Carolina. The Court admitted seventy-three exhibits and received testimony from witnesses who appeared at trial and by video depositions.

17. The parties submitted proposed findings of fact and conclusions of law on July 30, 2018, and all issues and claims are now ripe for determination.

III. GENERAL RULES OF CONTRACT CONSTRUCTION

18. When construing the 2012 Agreement, the Court has been guided by and has adhered to the following rules of contract construction. Although these standards may be properly considered, and are adopted, as part of the Court's Conclusions of Law, they are set out here to provide context for the Court's Findings of Fact. After making Findings of Fact, the Court makes further Conclusions of Law, which apply these rules of construction to the facts as the Court has found them to be.

19. "Whenever a court is called upon to interpret a contract its primary purpose is to ascertain the intention of the parties at the moment of its execution." *Lane v. Scarborough*, 284 N.C. 407, 409–10, 200 S.E.2d 622, 624 (1973). To do so, the Court must first look to the language of the contract and determine if it is clear and unambiguous. Where "the plain language of a contract is clear, the intention of the parties is inferred from the words of the contract." *Walton v. City of Raleigh*, 342 N.C. 879, 881, 467 S.E.2d 410, 411 (1996). If the terms of the contract are unambiguous, then the court must interpret the contract as a matter of law and "cannot look beyond the terms of the contract to determine the intention of the parties." *Stovall v. Stovall*, 205 N.C. App. 405, 410, 698 S.E.2d 680, 684 (2010) (quoting *Lynn v. Lynn*, 202 N.C. App. 423, 431, 698 S.E.2d 198, 205 (2010)).

20. In some instances, the intent of the parties cannot be determined solely from the words of the contract. "An ambiguity exists in a contract if the 'language of a contract is fairly and reasonably susceptible to either of the constructions asserted by the parties.'" *Crider v. Jones Island Club, Inc.*, 147 N.C. App. 262, 267, 554 S.E.2d

863, 866–67 (2001) (quoting *Barett Kays & Assocs., P.A. v. Colonial Bldg. Co.*, 129 N.C. App. 525, 528, 500 S.E.2d 108, 111 (1998)). "[I]f there is any uncertainty as to what the agreement is between the parties, a contract is ambiguous." *Crider*, 147 N.C App. at 267, 554 S.E.2d at 867.

21. If a court finds a contract ambiguous, the intent of the parties becomes a question of fact. In that instance, "the language used, the subject matter, the end in view, the purpose sought, and the situation of the parties at the time" can all aid the factfinder in determining the intentions of the parties. *Cordaro v. Singleton*, 31 N.C. App. 476, 479, 229 S.E.2d 707, 709 (1976); *see also Century Commc'ns, Inc. v. Hous. Auth. of Wilson*, 313 N.C. 143, 146, 326 S.E.2d 261, 264 (1985) (noting that where contractual "language is uncertain or ambiguous, the court may consider all the surrounding circumstances, including those existing when the document was drawn, those existing during the term of the instrument . . . , and the construction which the parties have placed on the language, so that the intention of the parties may be ascertained and given effect"). The Court should review "the entire instrument" and "cannot reject what the parties inserted or insert what the parties elected to omit." *Weyerhaeuser Co. v. Carolina Power & Light Co.*, 257 N.C. 717, 719, 127 S.E.2d 539, 541 (1962). The terms of a contract "'are to be harmoniously construed, and if possible, every word and every provision is to be given effect.'" *WakeMed v. Surgical Care Affiliates, LLC*, 243 N.C. App. 820, 824, 778 S.E.2d 308, 312 (2015) (quoting *In re Foreclosure of a Deed of Trust*, 210 N.C. App. 409, 415, 708 S.E.2d 174, 178 (2011)).

22. "[T]he law imputes to a person an intention corresponding to the reasonable meaning of his words and acts." *Howell v. Smith*, 258 N.C. 150, 153, 128 S.E.2d 144, 146 (1962). The "'legal consequences are not dependent upon the impressions or understandings of one alone of the parties to it. It is not what either thinks, but what both agree.'" *N. & W. Overall Co. v. Holmes*, 186 N.C. 428, 431, 119 S.E. 817, 818–19 (1923) (quoting *Prince v. McRae*, 84 N.C. 674, 675 (1881)). "[M]ental assent to the promises in a contract is not essential." *Howell*, 258 N.C. at 153, 128 S.E.2d at 146 (citing 17 C.J.S., Contracts § 32).

23. To determine the true intent of the parties, courts should consider "all the surrounding circumstances," especially "the construction which the parties have placed on the language" of the contract prior to the parties' dispute. *Century Commc's*, 313 N.C. at 146, 326 S.E.2d at 264. This common law principle is embodied in the Uniform Commercial Code, which recognizes that course of performance, course of dealing, and usage of trade may also explain or supplement the written agreement. N.C. Gen. Stat. § 25-2-202 (2017). The parties' actual course of performance may be the "best indication" of what the parties "intended the writing to mean." *Id.* § 25-2-202, Official cmt. 2.

24. The Supreme Court of North Carolina has stated that "no court can go wrong by adopting the *ante litem motam* practical interpretation of the parties, for they are presumed to know best what was meant by the terms used in their engagements." *Heater v. Heater*, 53 N.C. App. 101, 105, 280 S.E.2d 19, 22 (1981) (citing *Cole v. Fibre Co.*, 200 N.C. 484, 488, 157 S.E.2d 857, 859 (1931)). The Supreme

Court of North Carolina has explained that "parties are presumed to know the intent and meaning of their contract better than strangers," therefore when parties "have placed a particular interpretation on their contract after executing it, the courts ordinarily will not ignore that construction which the parties themselves have given it prior to the differences between them." *Davis v. McRee*, 299 N.C. 498, 502, 263 S.E.2d 604, 607 (1980).

25. "Evidence of statements and conduct by the parties after executing a contract is admissible to show intent and meaning of the parties. 'The conduct of the parties in dealing with the contract indicating the manner in which they themselves construe it is . . . controlling in its construction by the court.'" *Heater*, 53 N.C. App. at 104, 280 S.E.2d at 21–22 (quoting *Bank v. Supply Co.*, 226 N.C. 416, 432, 38 S.E.2d 503, 514 (1946)); *see also Joyner v. Adams* 87 N.C. App. 570, 574, 361 S.E.2d 902, 904 (1987) ("Evidence of the parties' purposes in entering a contract and their conduct after the agreement is some evidence of their intent.").

26. When faced with ambiguity, the Court cannot substitute its own intent, but can only enforce the agreement reached by the parties. "Under longstanding North Carolina law, a valid contract requires (1) assent; (2) mutuality of obligation; and (3) definite terms." *Charlotte Motor Speedway, LLC v. Cty. of Cabarrus*, 230 N.C. App. 1, 7, 748 S.E.2d 171, 176 (2013). "It is a well-settled principle of contract law that a valid contract exists only where there has been a meeting of the minds as to all essential terms of the agreement." *Northington v. Michelotti*, 121 N.C. App. 180, 184, 464 S.E.2d 711, 714 (1995). The parties "must assent to the same thing in the

same sense, and their minds must meet as to *all* the terms." *MCB, Ltd. v. McGowan*, 86 N.C. App. 607, 608, 359 S.E.2d 50, 51 (1987).

IV. FINDINGS OF FACT

27. The Court makes the following findings of fact based on the testimony presented and documentary evidence admitted. The evidence presents mixed issues of law and fact. Any determination later stated as a conclusion of law that should have been stated as a finding of fact is incorporated in these Findings of Fact.

28. The Court incorporates by reference the parties' factual stipulations filed on July 6, 2018, (ECF No. 125), and the parties' stipulations stated in the Final Pretrial Order entered on July 9, 2018. (ECF No. 129).

29. While the Court cites specifically to certain portions of the record in this Opinion & Final Judgment, the citations are for ease of reference. Those citations do not represent all the evidence upon which these Findings of Fact are based. The Court has considered the credibility of the witnesses in light of all evidence presented.

A. The Parties

30. CTG is a Delaware corporation that manufactures and sells wallboard, commonly referred to as drywall. CTG is the successor-in-interest to BPB NC Inc., which negotiated and executed the 2004 Agreement. (Factual Stipulations ¶ 1.)

31. DEP is a North Carolina limited-liability company. DEP is the successor-in-interest to Progress Energy, Inc. and Carolina Power & Light Company.[1] (Factual Stipulations ¶ 2.)

32. DEP owns and operates multiple power-generating plants in North Carolina and other states. DEP has different fuel sources for its power-generating plants—some plants are powered by natural gas and others are powered by coal. Some plants have multiple power-generating units. DEP's coal-fired Roxboro Plant has four generating units, and its coal-fired Mayo Plant has one generating unit.

33. DEP is a regulated public utility, and as such is required to provide "reliable and economical utility service[s]." N.C. Gen. Stat. § 62-2(3) (2017). DEP refers to this requirement as its "Primary Purpose." (*See* Ex. 15 § 3.9.) DEP is required to commit and dispatch its power-generating units in an economical order, known as the "Least-Cost-Dispatch Requirement" or "Economic Dispatch." DEP considers multiple factors when determining which units to commit and dispatch, including the load forecast, what generation assets are available, the heat rates of those assets, the fuel costs of those assets, and the reliability of those assets. Essentially, DEP commits the least expensive unit first and then, as it needs more electricity, brings the next least expensive unit online.

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[1] Each of the Supply Agreements were executed by predecessors of one or both of the parties. The parties agree that CTG and DEP are bound by the 2012 Agreement. For simplicity, throughout this Opinion & Final Judgment when referring to the parties to the Supply Agreements, the Court will refer to CTG and DEP, acknowledging that the predecessor companies were the actual parties to the earlier agreements.

34. DEP and Duke Energy Carolinas ("DEC") entered into a joint dispatch agreement ("Joint Dispatch Agreement"), which is an operating protocol established as part of the merger between the two companies that allows DEP and DEC to aggregate their resources in determining the least-cost way of meeting their aggregate demand.

B. <u>The Beginning of CTG and DEP's Contractual Relationship and the 2004 Agreement</u>

35. Federal legislation, commonly called the Clean Air Act, and related North Carolina legislation, known as the Clean Smokestacks Act, required DEP in the 1990s and early 2000s to install flue gas desulfurization systems ("FGD Systems"), commonly referred to as "scrubbers," at its North Carolina coal-fired electric power-generating plants. (*See* Ex. 111.) The scrubbing process removes pollutants from the emissions generated during the coal-combustion process and generates significant quantities of synthetic gypsum as a byproduct. DEP generally tries to find a beneficial reuse for its byproducts.

36. Around mid-2002, Danny Johnson ("Johnson"), a professional project manager at DEP, was searching for ways DEP could beneficially reuse the synthetic gypsum it expected to produce as a byproduct of the FDG Systems at DEP's Roxboro Plant and Mayo Plant. Johnson learned that synthetic gypsum is used to manufacture wallboard, to create cement, and as an agriculture soil amendment. (*See* Ex. 111.) At that time, DEP's Roxboro Plant and Mayo Plant were base-loaded power plants, meaning they were both high in the Economic Dispatch order and projected to be running constantly, resulting in the production of large quantities of

synthetic gypsum. At one point in Johnson's search, DEP estimated that by 2010, when the FGD Systems would be fully operational, the Roxboro Plant and Mayo Plant combined would produce 1.5 million tons of synthetic gypsum annually. (Ex. 111.)

37. DEP is not a broker of synthetic gypsum, nor does it have any use for synthetic gypsum in its normal operations. Thus, it needed to find a cost-effective method to beneficially reuse the synthetic gypsum. Absent such a use, DEP would incur significant costs to landfill the synthetic gypsum, which Johnson estimated to be approximately five dollars per ton. (Ex. 111.)

38. Around that same time, Peter Mayer ("Mayer"), CTG's Vice President of Technical Services, was in charge of finding a location in the Southeast United States for CTG to construct a wallboard-manufacturing plant ("CTG Plant"). Gypsum comprises about 90% of the raw materials needed to produce wallboard. Natural gypsum is not readily available in the Southeast. In searching for a location, CTG's main priority was finding a secure source of large quantities of synthetic gypsum. CTG needed to construct a plant near a supply of synthetic gypsum, because synthetic gypsum is heavy and extremely costly to transport. Mayer identified DEP's Roxboro Plant as a potential source of a large supply of synthetic gypsum.

39. Johnson learned of CTG's interest. He prepared a summary to his supervisors, stating that, after meeting with "all major wallboard manufacturers to understand their synthetic gypsum needs," he believed CTG "provided the most attractive opportunity through their desire to locate a wallboard facility at Roxboro

[and] pay for the gypsum material, and [because CTG] had a strong balance sheet." (Ex. 111.)

40. Mayer and Johnson then pursued discussions in an effort to fashion a mutually beneficial relationship, whereby CTG would build a manufacturing plant directly adjacent to DEP's Roxboro Plant. The intent was for DEP to achieve a beneficial reuse for its synthetic gypsum and CTG to have a secure supply of synthetic gypsum. At that time, CTG contemplated that its plant, upon completion and running at full capacity, would require approximately 600,000 tons of net dry synthetic gypsum annually.

41. DEP agreed to sell 120 acres of land adjacent to the Roxboro Plant to CTG, and CTG agreed to purchase such land and construct the CTG Plant.

42. Both CTG and DEP sought a long-term reciprocal commitment. Mayer indicated that multi-year supply contracts are typical in the wallboard industry. Both parties were motivated by long-range financial considerations. DEP was making a substantial investment in its FGD Systems and was facing millions of dollars in costs if it was unable to find a reliable, beneficial use for its synthetic gypsum byproduct. DEP also expected to incur the expense of constructing a conveyor system to deliver the Gypsum Filter Cake to the CTG Plant. (Ex. 5 § 2.2.) CTG contemplated a substantial capital investment to build the CTG Plant. When it decided to construct the CTG Plant, CTG knew that it would be dependent on DEP for its supply of synthetic gypsum at that plant because there was no other supplier

in close proximity, transportation costs were high, and there was no road or rail infrastructure to provide CTG an ability to access alternative sources.

43. DEP and CTG executed their first Supply Agreement—the 2004 Agreement—on February 12, 2004. Mayer and Johnson were the primary negotiators for the 2004 Agreement. Mayer was assisted by fellow CTG employees John College ("College") and Rob Morrow ("Morrow"), Vice-President of Supply Chain Management. The 2004 Agreement was, in substantial part, a forward-looking agreement, in that, at the time of its execution, neither party had made the financial investments they contemplated.

44. In order for CTG and DEP to induce the other's investment and to accommodate their ongoing needs, both parties determined that it was in their respective best interests to enter a long-term relationship and to make long-term commitments in exchange for long-term opportunities. The evidence is clear that DEP determined that entering a long-term agreement was in its best interest and consistent with its Primary Purpose as a regulated public utility.

45. The parties agreed to a twenty-year initial term measured "from the date on which the [CTG Plant] accepts the first delivery of Gypsum Filter Cake from [DEP]." (Ex. 5 § 8.1.) The 2004 Agreement further allowed for two additional extension periods of ten years each. (Ex. 5 § 8.2.)

46. The 2004 Agreement established a timeline in which DEP would construct the FGD Systems for the four Roxboro Plant units and the one Mayo Plant unit. (*See* Ex. 5 § 2.1.) DEP estimated that the first FGD Systems would begin

operation in the Spring of 2007 and that the final FGD Systems would be operational by the Spring of 2009. (*See* Ex. 5 § 2.1.) The parties agreed that, if DEP failed to complete the FGD Systems within six months of the completion dates agreed to and, as a result of such failure, DEP was unable to supply the MMQ of Gypsum Filter Cake after the CTG Plant was complete and ready to begin production, then CTG "shall be entitled to the remedies set forth in Section 6.2 of this Supply Agreement." (Ex. 5 § 2.1.) The Court finds that this provision was specific to DEP's potential failure to install its FGD Systems, and that the parties did not intend for this language to address, one way or the other, how Section 6.2 would apply for breaches occurring after the FGD Systems were installed.

47. The 2004 Agreement envisioned that the CTG Plant would be operational by late 2007 or early 2008. (Ex. 5 § 2.3.)

48. The 2004 Agreement defined the MMQ as "50,000 Net Dry Tons of Gypsum Filter Cake to be delivered on a monthly basis in accordance with Section 3.1." (Ex. 5 § 1.23.) Accordingly, the 2004 Agreement defined the MMQ in the agreement's definitional article and Section 3.1 provided the method of delivery and the time period when the MMQ would be implemented. DEP's obligation to deliver and CTG's obligation to accept Gypsum Filter Cake would begin once the CTG Plant was constructed. A lesser quantity of 30,000 net dry tons would be delivered and accepted during a six-month start-up period ("Start-Up Period"), after which the MMQ would apply. (Ex. 5. § 1.33; *see* Ex. 5 § 3.1.) Section 3.1 allowed for a permissible monthly variance from the MMQ, 10% up or down, so long as the monthly

average for any twelve-month period after the Start-Up Period was approximately equal to the MMQ of 50,000 net dry tons. (Ex. 5 § 3.1.) The 2004 Agreement recognized that DEP may produce more Gypsum Filter Cake than the MMQ, and such amount was defined as "Excess Gypsum," in which CTG was given the first refusal rights to purchase, and DEP had the first refusal rights to supply. (*See* Ex. 5 § 3.5.)

49. The 2004 Agreement also provided that DEP "will build and use reasonable efforts to maintain a 300,000 Net Dry Ton Gypsum Filter Cake stockpile." (*See* Ex. 5 § 2.2.)

50. The parties set forth the price at which CTG would purchase and DEP would sell Gypsum Filter Cake and the specific quality specifications for the Gypsum Filter Cake. (*See* Ex. 5 §§ 3.2, 4.1.)

51. The 2004 Agreement included an article defining respective remedies for failures to deliver or accept Gypsum Filter Cake. (*See* Ex. 5 §§ 6.1–6.5.) It also included an exclusive remedies clause. (Ex. 5 § 9.4.) In substantial part, those remedy provisions were carried forward in the 2008 Agreement and the 2012 Agreement.

52. The parties also agreed that "[i]f a legal action is initiated by any Party to this Agreement against another . . . any and all fees, costs, and expenses reasonably incurred by each successful Party . . . shall be the obligation of and shall be paid or reimbursed by the unsuccessful Party." (Ex. 5 § 16.7; *see also* Ex. 15 § 16.7.) This section remained unchanged in the 2008 Agreement and the 2012 Agreement.

C. <u>The 2008 Agreement</u>

53. The parties never actually delivered and accepted Gypsum Filter Cake under the 2004 Agreement before it was superseded by the 2008 Agreement.

54. DEP began installing the FGD Systems in 2007 as scheduled. However, CTG desired to delay its plant construction because of the adverse effect of the 2007 housing market crash and the Great Recession. But CTG did not abandon its ultimate goal to build its plant and establish a presence in the Southeast market; therefore, CTG needed to maintain its relationship with DEP in order to ensure a secure supply of synthetic gypsum once it built the CTG Plant.

55. On December 20, 2007, CTG contacted DEP in an effort to secure an agreement to maintain the supply agreement but delay construction of the CTG Plant. (*See* Ex 16.) CTG assured DEP that it "remain[ed] committed to the construction and operation of the plant with a start of production before November 2011." (Ex. 16, at 1.) CTG further assured DEP that it would take any actions necessary to preserve the relationship, including taking steps to "ensure that we meet our obligations to accept synthetic gypsum under the supply agreement, that we do not add additional financial burden to your organization and that we do not impair the operations of the power plants." (Ex. 16, at 2.)

56. Although DEP expressed frustration with CTG's delay, it ultimately agreed to negotiate a revised agreement, and proposed fourteen terms it wanted to discuss, including CTG paying to expand the Stockpile storage capacity from 300,000

tons to 650,000 tons and increasing CTG's purchase obligations "to a level at or near [CTG's] Plant's capacity." (Ex. 17 ¶ 10; *see* Ex. 17 ¶ 5.)

57. The primary negotiators for the 2008 Agreement were Morrow, on behalf of CTG, and for DEP Barbara Coppola ("Coppola"), a Coal Byproducts and Reagents Manager, and Daniel Mottola ("Mottola"), a Byproducts Specialist. Negotiations leading to the 2008 Agreement occurred between January 2008 and March 2008.

58. The 2008 Agreement became effective on March 28, 2008. (Ex. 6, at 1.) Similar to the 2004 Agreement, the parties agreed that the 2008 Agreement would "expire twenty (20) years from the date on which the [CTG Plant] accepts the first delivery of Gypsum Filter Cake from [DEP]" ("2008 Term"). (Ex. 6 § 8.1.)

59. The 2008 Agreement eliminated the Start-Up Period defined in the 2004 Agreement and provided that CTG's obligation to accept Gypsum Filter Cake would begin "on the earlier of (a) November 1, 2008 or (b) when the Loading Facility is in Commercial Operation . . . .," each of which were before the CTG Plant would be operational. (Ex. 6 § 3.1.) Once CTG's obligation was triggered, and for the remainder of the 2008 Term, CTG was required to accept and DEP was required to deliver the MMQ of 50,000 net dry tons of Gypsum Filter Cake. (*See* Ex. 6 § 3.1.)

60. CTG did not have its own storage facility in Roxboro, North Carolina. Thus, prior to the CTG Plant being operational, CTG had to take steps to transport and utilize or dispose of any Gypsum Filter Cake it was required to accept.

D. CTG and DEP's Performance Under the 2008 Agreement

61. CTG first accepted Gypsum Filter Cake on May 1, 2009. CTG constructed rail facilities in Roxboro, North Carolina, and at its Toronto and Montreal, Canada wallboard-manufacturing plants, which allowed CTG to transport and then use the Gypsum Filter Cake.

62. The CTG Plant began operations on March 28, 2012. Between May 1, 2009 and March 28, 2012, CTG accepted Gypsum Filter Cake and removed it from Roxboro by: (1) shipping it by rail from the Roxboro Plant to CTG's other wallboard-manufacturing plants; (2) landfilling both at a third-party landfill and at DEP's on-site landfill; and (3) subsidizing DEP's sale of synthetic gypsum to third parties. Ultimately, CTG spent over $32,800,000 prior to March 28, 2012 in an effort to take and dispose of Gypsum Filter Cake before the CTG Plant became operational. (*See* Ex. 142, at 9.) Even after the CTG Plant began operations, CTG continued to spend money to dispose of or transport Gypsum Filter Cake until it was able to fully utilize its deliveries.

63. Throughout this period, DEP did not demand and CTG did not typically accept the contractual MMQ. Between May 2009 and August 2012, CTG accepted the MMQ eight times. (Factual Stipulations, Ex. 1.)

64. During this period, DEP consistently maintained that the 2008 Agreement obligated CTG to accept the MMQ. (*See* Exs. 124–25.) However, rather than demanding CTG's full compliance, DEP worked cooperatively with CTG to limit CTG's acceptance to only levels necessary to maintain the Stockpile at a safe volume.

65. Between 2008 and 2011, there was a decreased demand for wallboard as a result of the Great Recession, causing CTG to have more synthetic gypsum than it could utilize at its various manufacturing plants. David Engelhardt ("Engelhardt"), CTG's Senior Vice President of Operations, who later became CTG's President, testified that at that time, and for a period thereafter, CTG's need for synthetic gypsum was significantly less than its contractual obligations to purchase synthetic gypsum, both from DEP and pursuant to other supply agreements. Thus, CTG's management tried to address concerns regarding its inability to meet those contractual obligations. On March 6, 2009, CTG management considered a presentation captioned "Roxboro & Moundsville Excess DSG—A Mountain of DSG." (Ex. 35.) The presentation reflects that CTG hoped to modify its agreements with DEP to accept quantities "at production rate[s] rather than obligation rate[s]." (Ex. 35, at 5.) Essentially, CTG wanted to shift its acceptance obligation under the agreement from a fixed MMQ to a requirement that would vary based on DEP's actual synthetic gypsum production and CTG's needs. (Ex. 35, at 5.)

66. Engelhardt testified that CTG expected that it would be able to accept and use the MMQ from DEP once the CTG Plant was fully operational, even if it had an oversupply for other plants, in part because CTG planned to redirect manufacturing from older plants to the new CTG Plant, with its more efficient manufacturing capabilities.

67. On November 19, 2009, the parties amended the 2008 Agreement by executing the First Amendment to Amended and Restated Supply Agreement ("First

Amendment"), pursuant to which CTG agreed to incur the expense to landfill at least 80,000 tons of Gypsum Filter Cake at the DEP on-site landfill and remove sufficient tonnage from the Stockpile to reduce it to less than 600,000 tons. (*See* Ex. 59 ¶ 3.)

68. The parties further amended the 2008 Agreement by executing a Second Amendment to Amended and Restated Supply Agreement ("Second Amendment") on June 25, 2010. (*See* Ex. 14.) The parties agreed in the Second Amendment that, for the remainder of 2010, CTG would only be obligated to accept the amount of Gypsum Filter Cake actually produced at the Roxboro Plant and Mayo Plant. (*See* Ex. 14 ¶ 3.) The Second Amendment also provided that CTG would remove and incur the cost to landfill 200,000 net dry tons of Gypsum Filter Cake from the Stockpile. (*See* Ex. 14 ¶ 2.)

E. The 2012 Agreement

69. CTG began constructing the CTG Plant in 2011. Construction presented some operational issues, including the method that would be used to transport Gypsum Filter Cake from DEP to the CTG Plant. The parties agreed that CTG could build, operate, and maintain equipment at DEP's storage facility to facilitate delivering Gypsum Filter Cake to the CTG Plant directly from the Stockpile. (*See* Ex. 28; Ex. 15 § 2.2.1.) The 2008 Agreement had to be modified, at a minimum, to accommodate these operational issues.

70. Between June 2011 and February 2012, Coppola and Engelhardt negotiated the 2012 Agreement with an effective date of August 1, 2012. As CTG had accepted its first delivery of Gypsum Filter Cake on May 1, 2009, the term of the 2012

Agreement was fixed at twenty years from that date. Accordingly, the 2012 Agreement is in effect until April 2029. (Ex. 15 § 8.1; *see also* Ex. 28, at 2.) The 2012 Agreement superseded the 2004 Agreement and the 2008 Agreement while carrying forward much of the substance of the earlier agreements without changes.

71. Engelhardt was the first to propose a draft of the 2012 Agreement. Consistent with the objective reflected in the March 6, 2009 presentation considered by CTG management, Engelhardt proposed amending the MMQ to shift from a fixed contractual supply obligation to one that varied with the parties' variable business operations. DEP rejected most of Engelhardt's changes, including his MMQ proposal, expressing a preference to maintain the supply quantity as it existed.

72. The Court now further makes its findings regarding the four major areas of dispute, which concentrate on these sections of the 2012 Agreement: Section 3.1 (MMQ); Section 2.2.3 (Stockpile); Section 3.9 (Primary Purpose); and Article 6, read in conjunction with Section 9.4 (remedies).

F. Disputed Terms of the 2012 Agreement

(1) Section 3.1—The Minimum Monthly Quantity

73. The parties' dispute as to the quantity term of the 2012 Agreement centers on Section 3.1.

74. Section 3.1 as adopted in the 2012 Agreement reads:

> Commencing on May 1, 2009 and continuing until the earlier of (i) the Commercial Operation Date or (ii) October 1, 2012, [DEP] agrees to sell and deliver to CertainTeed and CertainTeed agrees to purchase and accept from [DEP] at least 50,000 Net Dry Tons of Gypsum Filter Cake per month, subject to the allowance for fluctuations as set forth in this paragraph, and except as may otherwise be excused by the terms of this

> Revised Agreement. (The volume obligations set forth herein may be referred to as the **"Minimum Monthly Quantity"**.) In order to accommodate minor fluctuations in volumes actually delivered and accepted under this Revised Agreement, any quantities of Gypsum Filter Cake to be delivered under this Revised Agreement shall he deemed to be satisfied provided that such fluctuations (up or down) do not exceed ten percent (10%), and provided that the average monthly quantity of Gypsum Filter Cake delivered and accepted under this Revised Agreement over any twelve (12) month period after the Commercial Operation Date shall be approximately 50,000 Net Dry Tons, *or the aggregate actual Gypsum Filter Cake Net Dry Tons produced by the Roxboro Plant and the Mayo Plant over the same period, whichever is less.* [DEP's] expectation is to supply Gypsum Filter Cake primarily from the Roxboro Plant and Mayo Plant, but retains the right to supply Gypsum Filter Cake from any source.

(Ex. 15 § 3.1 (italics added).)

75. The italicized language was first added to Section 3.1 by the 2012 Agreement, and is the cornerstone of the parties' dispute as to whether the 2012 Agreement was intended to change the supply obligation as it had been understood in the earlier agreements. The parties agree that the MMQ was 50,000 Net Dry Tons of Gypsum Filter Cake, subject to acceptable minor fluctuations, in the 2004 Agreement and the 2008 Agreement. CTG contends that the parties' amendment to Section 3.1 in the 2012 Agreement did not change the base supply term of 50,000 Net Dry Tons of Gypsum Filter Cake, but only modified how acceptable minor fluctuations would be determined. DEP contends that the revised language changed the MMQ from a fixed quantity of 50,000 net dry tons to a variable quantity, which could be as low as DEP's actual production of Gypsum Filter Cake at its Roxboro Plant and Mayo Plant.

76. Prior to trial, the Court found, and again now finds, that the language of Section 3.1 is ambiguous. As more fully explained below, considering the language in the light of the extrinsic evidence presented, and particularly the historical negotiations that lead to the inclusion of Section 3.1 in the 2012 Agreement, the Court finds that the greater weight of the evidence demonstrates that the parties intended and agreed to carry forward the MMQ of 50,000 Net Dry Tons of Gypsum Filter Cake, subject to minor acceptable fluctuations, for the entire term of the 2012 Agreement, and that, by including the italicized language noted above, the parties further agreed to a modified method by which to determine those fluctuations.

(a) <u>The MMQ and Section 3.1 under the 2004 Agreement</u>

77. In the 2004 Agreement, the parties included Section 1.23 in Definitions-Article I to define MMQ to "mean 50,000 Net Dry Tons of Gypsum Filter Cake to be delivered on a monthly basis in accordance with Section 3.1." (Ex. 5 § 1.23.) Section 3.1 provided when the delivery obligation would be triggered and the minor fluctuations that would be acceptable each month. (Ex. 5 § 3.1.)

78. Section 3.1 set two defined time periods—(1) the Start-Up Period, defined as the "initial six (6) month period of commercial operations of the [CTG Plant]," and (2) the remainder of the 2004 Term after the Start-Up Period ("2004 Term"). (*See* Ex. 5 §§ 1.33, 3.1.) During the Start-Up Period, the parties were only required to deliver and accept 30,000 net dry tons of Gypsum Filter Cake. (*See* Ex. 5 §§ 1.33, 3.1.) After the Start-Up Period, DEP was required to deliver and CTG was required to accept the MMQ as defined in Section 1.23—50,000 net dry tons. (*See* Ex.

5 §§ 1.23, 3.1.) Section 3.1 also provided for allowable minor fluctuations, stating that the parties' obligations would be satisfied "provided that such fluctuations (up or down) do not exceed 10%." (Ex. 5 § 3.1.)

79. Section 3.1 provided in 2004, and has continued in all subsequent agreements to provide, that "[DEP's] expectation is to supply Gypsum Filter Cake primarily from the Roxboro Plant and Mayo Plant, but retains the right to supply Gypsum Filter Cake from any source." (Ex. 5 § 3.1.)

(b) Revisions to Section 3.1 in the 2008 Agreement

80. The parties made three significant changes to Section 3.1 in the 2008 Agreement. They agreed to: (1) eliminate the Start-Up Period, (2) add "Commercial Operation" dates, and (3) delete the definition of MMQ from the definitions article, leaving the MMQ to be defined only by the language of Section 3.1.

81. When negotiating the 2008 Agreement in light of CTG's construction delay, DEP proposed that provisions related to the Start-Up Period in which CTG was obligated to accept less than the MMQ should be eliminated, and that the MMQ should be increased from 50,000 net dry tons to 55,000 net dry tons after CTG began or should have begun Commercial Operation. DEP then proposed two periods with a different MMQ. Its proposed Section 3.1 read as follows:

> Commencing on the earlier of (a) November 1, 2008 or (b) when the Loading Facility is in Commerical Operation and continuing until the earlier of (i) the date the CertainTeed Manufacturing Plant commences Commercial Operation or (ii) November 1, 2011 [("Commercial Operation Period")], [DEP] agrees to sell and deliver to CertainTeed and CertainTeed agrees to purchase and accept from [DEP] at least 50,000 Net Dry Tons of Gypsum Filter Cake per month, subject to the allowance for fluctuations as set forth in this paragraph, and except as may

> otherwise be excused by the terms of this Amended Agreement [("Commercial Operation Period MMQ")]. *Commencing on the earlier of (x) the date the CertainTeed Manufacturing Plant commences Commerical Operation or (ii) November 1, 2011, and continuing throughout the remainder of the Term of this Agreement [("2008 Term")], [DEP] agrees to sell and deliver to CertainTeed and Certainteed agrees to purchase and accept from [DEP] at least 55,000 Net Dry Tons of Gypsum Filter Cake per month subject to the allowance for fluctuations as set forth in this paragraph, and except as may otherwise be excused by the terms of this Amended Agreement* [("2008 Term MMQ")]. (The volume obligations set forth herein may be referred to as applicable the "Minimum Monthly Quantity.") In order to accommodate minor fluctuations in volumes actually delivered and accepted under this Amended Agreement, any quantities of Gypsum Filter Cake to be delivered under this Amended Agreement shall be deemed to be satisfied provided that such fluctautions (up or down) do not exceed 10%, and provided that the average monthly quantity of Gypsum Filter Cake delivered and accepted under this Amended Agreement over any twelve (12) month period after the Start-up Period shall be approximately 50,000 Net Dry Tons. [DEP's] expectation is to supply Gypsum Filter Cake primarily from the Roxboro Plant and Mayo Plant, but retains the right to supply Gypsum Filter Cake from any source.

(Ex. 11 § 3.1 (emphasis added).)

82. DEP's proposed amendment did not change either the definition of acceptable minor fluctuations or the language retaining DEP's ability to supply synthetic gypsum from any source.

83. The parties met to discuss DEP's proposed changes on February 14 and 15, 2008. CTG agreed to eliminate the Start-Up Period, but did not agree to increase the MMQ to 55,000 net dry tons. The net effect was to provide a single definition of the MMQ as 50,000 net dry tons, subject to the agreed fluctuations.

84. On February 18, 2008, DEP's attorney circulated a draft intended to incorporate the agreements reached at the February meeting ("February 2008 Draft"). The February 2008 Draft was not produced in a redline format to show the

revisions that were rejected, changed, or agreed to. (*See* Ex. 18.) Section 3.1 in the February 2008 Draft read as follows:

> <u>Delivery of Gypsum</u>. Commencing on the earlier of (a) November 1, 2008 or (b) when the Loading Facility is in Commercial Operation and continuing until the earlier of (i) the date the CertainTeed Manufacturing Plant commences Commercial Operation or (ii) November 1, 2011, [DEP] agrees to sell and deliver to CertainTeed and CertainTeed agrees to purchase and accept from [DEP] at least 50,000 Net Dry Tons of Gypsum Filter Cake per month, subject to the allowance for fluctuations as set forth in this paragraph, and except as may otherwise be excused by the terms of this Amended Agreement. (The volume obligations set forth herein may be referred to as the "**Minimum Monthly Quantity**".) In order to accommodate minor fluctuations in volumes actually delivered and accepted under this Amended Agreement, any quantities of Gypsum Filter Cake to be delivered under this Amended Agreement shall be deemed to be satisfied provided that such fluctuations (up or down) do not exceed 10%, and provided that the average monthly quantity of Gypsum Filter Cake delivered and accepted under this Amended Agreement over any twelve (12) month period after the Start-up Period shall be approximately 50,000 Net Dry Tons. [DEP's] expectation is to supply Gypsum Filter Cake primarily from the Roxboro Plant and Mayo Plant, but retains the right to supply Gypsum Filter Cake from any source.

(Ex. 18 § 3.1 (emphasis in original).)

85. The February 2008 Draft eliminated the entire sentence in DEP's earlier draft that would have defined a period after the Commercial Operation Period in which the MMQ would be increased to 55,000 net dry tons. As a result, the February 2008 Draft did not expressly include any MMQ for the contract term remaining after the earlier of November 2011 or the start of the Commercial Operation Period.

86. Neither the negotiators nor counsel recognized that omission. Ultimately, the parties executed the 2008 Agreement, adopting Section 3.1 as shown in the February 2008 Draft. (*See* Ex. 6 § 3.1; *see also* Ex. 18 § 3.1.)

87. Despite the fact that Section 3.1 of the 2008 Agreement, as adopted, did not explicitly state a quantity term for the remainder of the 2008 Term, the parties agree that the MMQ under the 2008 Agreement was 50,000 net dry tons for the entire term of the 2008 Agreement, subject to the acceptable minor fluctuations. Morrow and Coppola both testified that their understanding and intent was to move the definition of MMQ to Section 3.1 and that the MMQ was to be 50,000 net dry tons for the entire term of the 2008 Agreement, subject to minor fluctuations.

88. The Court finds that a drafting error resulted in there being no express MMQ for the entire term of the 2008 Agreement, but that notwithstanding that error and omission, under the 2008 Agreement, the parties intended, understood, and agreed that the MMQ was 50,000 net dry tons during both the Commercial Operation Period and the remainder of the 2008 Term, subject to the acceptable minor fluctuations, which remained unchanged from the 2004 Agreement. This drafting error did not affect the provision of Section 3.1 regarding DEP's expected source of Gypsum Filter Cake to meet its supply obligation, which was carried forward from the 2004 Agreement without change.

(c) Section 3.1 of the 2012 Agreement

89. Section 3.1 in the 2012 Agreement varies from the 2008 Agreement in two ways: (1) the definition of the Commercial Operation Period changed; and (2) the clause "or the aggregate actual Gypsum Filter Cake Net Dry Tons produced by the Roxboro Plant and the Mayo Plant over the same period, whichever is less" was

added. The Court will now refer to this added clause as the "Aggregate Actual Production Clause." (Ex. 15 § 3.1.)

90. The Commercial Operation Period was changed to start on May 1, 2009, when CTG accepted its first delivery of Gypsum Filter Cake, and to end on the earlier of (a) the actual commercial operation date of the CTG Plant or (b) October 1, 2012 ("2012 Commercial Operation Period"). (Ex. 15 § 3.1.)

91. Language that later became the Aggregate Actual Production Clause adopted in the 2012 Agreement originated in a draft Engelhardt proposed to begin negotiations for a new agreement. That clause must be considered in context. His proposed changes to Section 3.1 were accompanied by substantial other changes that DEP rejected. The Aggregate Actual Production Clause was the sole portion of Engelhardt's proposals to the 2008 Agreement that was incorporated into the final 2012 Agreement. CTG contends that the language in question was retained in order to change the acceptable minor fluctuations, but that the parties did not intend to change the fixed MMQ that had been in place since 2004. DEP contends that the Aggregate Actual Production Clause was retained in Section 3.1 because DEP accepted CTG's proposal to replace a fixed MMQ with one that fluctuated based on production at its Roxboro Plant and Mayo Plant.

92. The Court agrees with CTG and finds that the parties did not intend for the Aggregate Actual Production Clause to change the supply and acceptance obligations, but rather the parties understood, intended and agreed that the MMQ throughout the term of the 2012 Agreement, ("2012 Term"), would continue to be

50,000 net dry tons, and the Aggregate Actual Production Clause was intended, understood, agreed only to modify the method to determine minor fluctuations without otherwise modifying the MMQ from which those fluctuations are measured.

93. When negotiating the 2012 Agreement, Engelhardt proposed not only substantial changes to Section 3.1, but also provisions regarding the Stockpile and other modifications that would allow either party to receive the essential benefit of the supply agreement even if the quantities supplied or accepted from month to month varied to a degree larger than the 10% variances allowed by Section 3.1 of the 2004 Agreement and the 2008 Agreement. Engelhardt testified that he intended to provide both CTG and DEP flexibility consistent with the actual month-to-month and seasonal variations in production, but with protections through the Stockpile to ensure that each party would receive the expected benefit of the agreement.

94. First, Engelhardt proposed a shift from a monthly emphasis to an annual term, with any default to be measured against that annual quantity. (*See* Ex. 23 § 1.30; *see, e.g.*, Ex. 23 § 6.2 (stating in a redlined draft the remedies available to CTG "in the event [DEP] is unable to deliver to CertainTeed the Minimum Annual ~~Monthly~~ Quantity in any year ~~month~~ during the Term of this Revised Agreement and the stockpile falls below 100,000 Net Dry Tons . . . .").) Engelhardt also proposed a new MMQ of 25,000 net dry tons per month, which would be an absolute minimum amount the parties could deliver and accept each month, but the primary focus would be satisfying the annual obligations.

95. Second, Engelhardt proposed that the parties agree to maintain an absolute minimum and maximum volume for the Stockpile to protect their respective needs ("Stockpile Buffer"). The minimum would be set at 100,000 net dry tons, assuring that CTG would always have access to at least two months' supply, and the maximum would be set at 600,000 net dry tons, with CTG required to remove any excess. (*See* Ex. 23 § 2.2.3(c).)

96. Third, Engelhardt substantially revised Section 3.1 to accommodate these changes. Engelhardt's proposed Section 3.1 stated:

> Commencing on May 1, 2009 and continuing until the earlier of (i) the date the CertainTeed Manufacturing Plant commences Commercial Operation or (ii) October 1, 2012, [DEP] agrees to sell and deliver to CertainTeed and CertainTeed agrees to purchase and accept from [DEP] at least *600.000* [sic] Net Dry Tons of Gypsum Filter cake per *year or the quantity of Gypsum Filter Cake produced by [DEP] during the said year, whichever is less, subject to the Stockpile in the [DEP] Storage Area not exceeding 600,000 Net Dry Tons,* and except as may otherwise be excused by the terms of this Revised Agreement. (The volume obligations set forth herein may be referred to as the ***"Minimum Annual Quantity".***) *The Minimum Monthly Quantity of Gypsum Filter Cake that [DEP] agrees to sell and deliver to CertainTeed and that CertainTeed agrees to purchase and accept from [DEP] in any given month shall be 25,000 Net Dry Tons.* In order to accommodate minor fluctuations in volumes actually delivered and accepted under this Revised Agreement, any quantities of Gypsum Filter Cake to be delivered under this Revised Agreement shall be deemed to be satisfied provided that the average monthly quantity of Gypsum Filler [sic] Cake delivered and accepted under this Revised Agreement over any (12) month period after the beginning of the Commercial Operation shall be approximately 50,000 net dry tons, *or the actual Gypsum Filter Cake Net Dry Ton production over the same period, whichever is less.* [DEP's] expectation is to supply Gypsum Filter Cake primarily from the Roxboro Plant and Mayo Plant, but retains the right to supply Gypsum Filter Cake from any source. *Acceptance will include Gypsum Filter Cake conveyed to the CertainTeed plant, loaded into rail or trucks for transfer to other CertainTeed facilities, transferred to third parties, or added to the Stockpile providing that the Stockpile does not exceed 600,000 tons.*

(Ex. 23 § 3.1 (italics added).)

97. Engelhardt deleted the language in Section 3.1 of the 2008 Agreement that allowed fluctuations in the monthly quantity so long as "such fluctuations (up or down) do not exceed ten percent" and substituted the Actual Aggregate Production Clause. (*See* Ex. 23 § 3.1.) He then substituted his proposal that would allow fluctuations to be measured by production but still subject to the requirements of this Stockpile Buffer.

98. Under Engelhardt's proposal, CTG would be obligated to accept DEP's actual annual production of Gypsum Filter Cake or 600,000 net dry tons, whichever was less, *and* whatever amount of Gypsum Filter Cake was necessary to guarantee that the Stockpile did not exceed 600,000 net dry tons. In turn, DEP would be required to maintain at least 100,000 net dry tons of Gypsum Filter Cake in the Stockpile at all times, irrespective of what DEP actually produced at its Roxboro Plant and Mayo Plant.

99. Notably, Engelhardt's draft started from the language of Section 3.1 of the 2008 Agreement, which, as noted above, failed to include an express MMQ for the contract term remaining after the early Commercial Operation Period. He then carried forward the same mistaken omission that had occurred in 2008. It is clear, however, that Engelhardt intended to propose an annual supply obligation for the entire 2012 Term.

100. Engelhardt sent his proposed draft to Coppola on October 20, 2011. (*See* Ex. 23.) After receiving Engelhardt's draft, Coppola expressed that DEP "would like

to leave the volume obligation as is," but agreed that the parties could discuss possible changes. (Ex. 25.) At that time, Coppola was aware that DEP was projecting that for the next several years, its Roxboro Plant and Mayo Plant would produce Gypsum Filter Cake in excess of 600,000 tons per year.

101. Neither Engelhardt nor Coppola recall having extensive conversations between October 2011 and February 2012. E-mails suggest some discussion occurred in November 2011, but no such discussion is further documented. (*See* Ex. 25.) Coppola testified that she and Engelhardt discussed Engelhardt's proposed changes in detail, but she was unable to recall any specifics regarding such discussions. Engelhardt testified that he and Coppola, in fact, had very few conversations between October 2011 and finalizing the 2012 Agreement.

102. Coppola first provided Engelhardt a counterproposal on February 10, 2012 ("February 2012 Draft"). (*See* Ex. 26.) The February 2012 Draft rejected most of Engelhardt's proposed edits.

103. Specifically, DEP deleted "Minimum Annual Quantity" as a defined term and all references to a "Minimum Annual Quantity" included throughout the agreement. (*See, e.g.*, Ex. 26 §§ 1.30, 2.2.3(c), 3.1, 6.2.) DEP reverted back to the language of the 2008 Agreement. DEP rejected Engelhardt's revised monthly minimum of 25,000 net dry tons. DEP reinserted the clause allowing 10% fluctuations (up or down), but also left in the Aggregate Actual Production Clause, which Engelhardt had proposed in lieu of the 10% fluctuation. DEP's February 2012

Draft, like the 2008 Agreement, did not state a fixed quantity term for the contract period remaining after the 2012 Commercial Operation Period.

104. DEP rejected Engelhardt's proposal to create a Stockpile Buffer with a guaranteed minimum and maximum volume. (Ex. 26 §§ 1.48, 2.2.3(c).) Rather, DEP's February 2012 Draft contained no quantity requirements for the Stockpile. (*See* Ex. 26 § 2.2.3.)

105. Lead negotiators for the parties met on February 14, 2012, in an effort to reach a final agreement. There was no testimony as to any specific discussion of Section 3.1 at the parties' February meeting.

106. Ultimately, Section 3.1 in the 2012 Agreement was adopted as it had been proposed in DEP's February 2012 Draft.

107. Even though she could not recall any specific negotiations, Coppola now testifies that she specifically recalls that the parties intended and agreed to create a new variable quantity term for the contract period after the 2012 Commercial Operation Period. Coppola testified that to accomplish this purpose, DEP intentionally accepted the Aggregate Actual Production Clause in order to accept CTG's proposal to move from a fixed to a variable MMQ. She testified that the parties agreed that the variable MMQ after the 2012 Commercial Operation Period would be:

> the average monthly quantity of Gypsum Filter Cake delivered and accepted under this Revised Agreement over any twelve (12) month period after the Commercial Operation Date shall be approximately 50,000 Net Dry Tons, or the aggregate actual Gypsum Filter Cake Net Dry Tons produced by the Roxboro Plant and the Mayo Plant over the same period, whichever is less.

(Ex. 15 § 3.1.) Coppola is the sole witness who recalls DEP's intent to change the MMQ to a variable term that could fall below 50,000 net dry tons if DEP's production fell. Even Coppola was unable to testify as to any discussion with CTG in this regard.

108. Engelhardt testified that he believed that when DEP rejected his other proposed changes, Section 3.1 essentially reverted back to the volume obligations as stated in the 2008 Agreement, but that the parties slightly modified the method for determining the allowable minor fluctuations. He understood that the parties agreed that a party would be deemed to satisfy its obligations under Section 3.1 if the two minor fluctuation requirements were each satisfied: first, any fluctuations from the 50,000 MMQ could not exceed 10% (up or down), and second, the average monthly quantity over a twelve-month period must equal the lesser of 50,000 net dry tons (essentially 600,000 net dry tons per year), or DEP's aggregate actual production at the Roxboro Plant and Mayo Plant. Engelhardt testified that because both conditions had to be satisfied, the net effect was that the parties would satisfy their volume obligation so long as DEP delivered and CTG accepted at least 540,000 net dry tons of Gypsum Filter Cake per year, or a maximum of a 10% variation each month.

109. Engelhardt testified that he agreed to the inclusion of the Aggregate Actual Production Clause based on his understanding that the MMQ would be between 45,000 and 55,000 net dry tons per month. Engelhardt explained that by leaving in the Aggregate Actual Production Clause, the parties were allowing for some fluctuation to the volume obligations—although not the fluctuation he had

requested—and that a guarantee of at least 45,000 net dry tons per month was sufficient to satisfy CTG's needs.

110. The Court finds that Engelhardt's proposed changes must be understood and read in conjunction with all of his revisions, including the addition of a Minimum Annual Quantity term, the inclusion of a Stockpile Buffer, and the deletion of the 10% fluctuations clause.

111. The Court finds that the Aggregate Actual Production Clause Engelhardt proposed was not, initially or when adopted, intended by either party to change the MMQ from the fixed volume of 50,000 net dry tons per month, subject to minor fluctuations, to a new variable MMQ based on DEP's actual production at its Roxboro Plant and Mayo Plant. Rather, as Engelhardt proposed an alternative monthly quantity, he also proposed an alternative method to determine acceptable fluctuations to substitute for the existing method based on a 10% variation of the fixed 50,000 net dry ton supply obligation. Engelhardt intended to allow for greater monthly variations while maintaining an annual quantity obligation and requiring a Stockpile Buffer. The Court finds that Engelhardt's various proposed modifications of the parties' supply and acceptance obligations were subject to the parties also agreeing to Engelhardt's proposed Stockpile Buffer, and once DEP determined to remain with a fixed MMQ of 50,000 net dry tons, neither CTG nor DEP intended or agreed to accept Engelhardt's proposed language as anything other than a modification to the manner in which fluctuations from that MMQ would be acceptable.

112. Following Engelhardt's promotion to CTG President, on February 22, 2012, Kim Bildfell ("Bildfell"), CTG's Vice President of Purchasing and Customer Satisfaction, assumed responsibility for negotiating the 2012 Agreement on behalf of CTG. Bildfell testified that the negotiations concerning Section 3.1 had been completed before she began participating in the negotiations and that she was not involved in any further negotiations concerning Section 3.1. Instead, she focused on addressing the Stockpile requirements in Section 2.2.3 and finalizing the operational changes.

113. On March 7, 2012, while reviewing a draft of the 2012 Agreement, Bildfell noted a question as to whether the changes to Section 3.1 would allow DEP to reduce its supply of Gypsum Filter Cake below 50,000 net dry tons even if CTG were to require that amount. (*See* Ex. 46 ¶ 8 ("What if [DEP] makes less than 50,000 consistently and we need 50,000 . . . [Section 3.1] reads 50,000 net dry tons, or the aggregate actual Gypsum Filter Cake Net Dry Tons produced by the Roxboro Plant and the Mayo Plant. Does this mean [DEP] no [sic] responsible if [sic] produce less than 50,000 consistently[?]").) Bildfell believes that she discussed this concern with Engelhardt, but she does not recall any specifics of a discussion with Engelhardt or anyone else regarding her question about Section 3.1. She testified that at the time she signed the 2012 Agreement, she understood that the MMQ was 50,000 net dry tons per month for the entire 2012 Term.

114. The Court finds that Bildfell's comments do not evidence that the parties intended and agreed that Section 3.1 of the 2012 Agreement changed the MMQ from

what it has been understood to mean since it was first established in the 2004 Agreement.

115. Other contemporaneous documentation is consistent with the Court's finding.

116. On August 17, 2012, Coppola emailed her supervisors a summary of the major changes to the 2012 Agreement. Notably, Coppola made no direct or indirect reference to the parties' alleged agreement to change the MMQ to a variable supply term. To the contrary, Coppola stated that there were "[n]o changes to the original intent of the document," explaining that the "primary changes" made in the 2012 Agreement reflected the parties' agreement that CTG could install additional equipment to the DEP Storage Area. (Ex. 28.) Coppola repeatedly stated that the volume obligations did not change, concluding that "[n]o changes to Article 3 – Gypsum Sales – this is important because *there has been no change to the obligation to deliver material in the original volumes specified*" and "[a]gain, the original terms around pricing and *volumes* remained untouched." (Ex. 28, at 2 (emphases added).)

117. Coppola now testifies that her August 17, 2012 e-mail was inaccurate. Attempting to explain the error, Coppola stated that, at the time she drafted the e-mail, she was focused on the changes the parties had made concerning the construction modifications. She further testified that at the time she drafted the e-mail, DEP forecast that the actual production of Gypsum Filter Cake at the Roxboro Plant and Mayo Plant would be at least 600,000 net dry tons per year, meaning the

volume obligation would effectively remain the same and there would have been no need to document a supply obligation based on different production scenarios.

118. Contrary to her testimony at trial, the Court finds that throughout the negotiations for the 2012 Agreement, Coppola and DEP remained committed to keeping the quantity term as it was. (*See* Ex. 25 (stating that DEP "would like to leave the volume obligation as is").) Consistent with its intent to keep the supply obligation the same, DEP rejected the substance of Engelhardt's proposed changes.

119. The Court does not find Coppola's current recollection or testimony at trial, which varies from her contemporaneous documentation, to be credible. A change from a fixed quantity to a variable quantity term would have been a fundamental change to the parties' agreement. If there was a clear and intentional effort to accept portions of Engelhardt's proposed language to make this shift, it is fair to expect that Coppola would have advised her management of such change. Instead, she advised management that there was no change. Further, considering that this new variable term would require DEP to complete month-to-month calculations to determine its rolling twelve-month average production in order for the parties to determine the MMQ each month, it is fair to expect that Coppola would have advised those who were to oversee the performance of the contract that they needed to make the necessary monthly calculations. It is clear she did not. There is no testimony or document reflecting that Coppola told anyone at or around the time the 2012 Agreement was executed that the MMQ had changed. The Court finds that it is not credible that Coppola now recalls a specific intent, contrary to her written

documentation, that the parties intended or agreed to change the 50,000 net dry ton MMQ as understood in the 2008 Agreement. Rather, her documentation supports the finding that the parties intended that the MMQ was not changed, and only the method of determining acceptable fluctuations had been changed by the 2012 Agreement.

120. The Court finds that the greater weight of the evidence proves that neither CTG nor DEP intended to change the MMQ to the variable quantity term DEP now promotes in the litigation. Rather, the greater weight of the evidence leads the Court to find that both CTG and DEP intended and agreed to carry forward the MMQ of 50,000 net dry tons of Gypsum Filter Cake, as stated in the 2004 Agreement and the 2008 Agreement. As was the case when entering the 2008 Agreement, the parties intended this MMQ to apply for the entire term of the 2012 Agreement, although the language failed to expressly define a supply quantity for the entire contract term.

121. Based on the greater weight of the evidence, the Court further finds that the parties intended and agreed that Section 3.1, as modified in the 2012 Agreement, provides two separate clauses for determining acceptable fluctuations connected with the word "and," so that both clauses must be met in order for a fluctuation from the MMQ to be acceptable. Accordingly, the parties intended and agreed that their supply or acceptance obligations would be satisfied if DEP supplied and CTG accepted (1) an average monthly quantity of 50,000 net dry tons (essentially 600,000 net dry tons per year) or the aggregate actual production from the Roxboro Plant and Mayo

Plant over a twelve-month period, "whichever is less," and (2) the monthly quantity delivered and accepted does not vary more than 10% (up or down) from 50,000 net dry tons. Read together, these phrases provide that throughout the term of the 2012 Agreement, unless otherwise excused, DEP must supply and CTG must accept between 45,000 and 55,000 net dry tons per month and 540,000 and 600,000 net dry tons of Gypsum Filter Cake over a twelve-month period.

(d) The Parties' Performance between 2012–2016

122. The Court has not relied upon evidence of the parties' performance after executing the 2012 Agreement to determine the intent of the parties when entering that agreement. However, having heard the evidence presented, the Court finds that the parties' performance under the 2012 Agreement is consistent with the Court's finding that, when entering the 2012 Agreement, the parties intended and agreed for the MMQ to be 50,000 net dry tons for the entire 2012 Term as it had been for earlier agreements.

123. The CTG Plant became operational on March 28, 2012, initially running only one shift for the first month. The CTG Plant gradually increased its production—operating two shifts between May 2012 and October 2012, then increasing to three shifts in October 2012. Ultimately, the CTG Plant began operating four shifts and running at full capacity in April 2013.

124. CTG increased its acceptance of Gypsum Filter Cake from 2012 through 2014, but was still not regularly accepting 50,000 net dry tons per month. (Factual Stipulations, Ex. 1.) From March 2012 through July 2015, over two years after the

CTG Plant became fully operational, CTG had only accepted as much as 45,000 net dry tons of Gypsum Filter Cake during three months. (Factual Stipulations, Ex. 1.)

125. John Halm ("Halm"), a byproducts marketing manager for DEP, became responsible for managing and administrating the 2012 Agreement on behalf of DEP around October 2012. At that time, Halm administered the 2012 Agreement based on his understanding that DEP had an obligation to supply, and CTG had an obligation to accept, 50,000 net dry tons of Gypsum Filter Cake per month, subject to allowable fluctuations. Although Coppola's construction of the 2012 Agreement would require calculating DEP's rolling twelve-month average production at its Roxboro Plant and Mayo Plant each month, Coppola did not instruct Halm of this need.

126. Halm reported to Tony Mathis ("Mathis"), the manager of DEP's byproducts team. Beginning in 2015, Mathis reported to Brian Weisker ("Weisker"), Vice President of Coal Combustion Products Operations & Maintenance. Documents reflect that at least until they consulted with counsel in January 2017, Halm, Mathis, and Weisker, who were not involved in any negotiation leading to the 2012 Agreement, all understood, based on their reading of the agreement, that the MMQ under the 2012 Agreement was 50,000 net dry tons per month. (*See* Exs. 31, 32, 113, 114.) Both Halm's and Weisker's testimony at trial was consistent with the documentation.

127. Although the evidence is that CTG did not regularly accept 50,000 net dry tons (plus or minus 10%) between March 2012 and July 2015, there is no evidence

that DEP demanded that CTG do so. Nevertheless, DEP continued to represent that the MMQ was 50,000 net dry tons per month, informing CTG that DEP did not want CTG to discontinue its support for third-party sales until the Stockpile fell below 600,000 net dry tons and CTG was regularly accepting 50,000 tons per month. (*See* Ex. 130.)

128. In January 2016, Halm prepared a written summary of the 2012 Agreement reflecting his understanding that DEP was contractually obligated to supply 600,000 tons of synthetic gypsum per year and that DEP would be required to purchase synthetic gypsum from another source if the production at DEP's Roxboro Plant and Mayo Plant was not adequate to satisfy the MMQ. (*See* Ex. 31, at 3.) Halm noted that while CTG has actually required lesser amounts, he projected that DEP faced a future production shortage that would not meet the MMQ.

129. In January 2017, Weisker prepared a summary of the CTG contract and provided it to his superior, George Hamrick, Vice President of Coal Combustion Products. Weisker's summary acknowledged that DEP had a supply obligation of 600,000 tons per year that would require DEP to secure an alternative source of synthetic gypsum should its Roxboro Plant and Mayo Plant production be inadequate. (Ex. 113, at 1.)

130. Halm and Weisker testified that they changed their understanding regarding the MMQ after consulting counsel.

131. Between 2012 and early 2017, DEP never tracked or calculated the rolling twelve-month average of production at the Roxboro Plant and Mayo Plant.

April 6, 2017, was the first time Halm calculated the twelve-month rolling average to determine the MMQ.

132. The Court finds that the understanding that Halm and Weisker had before consulting counsel, and the management steps they took consistent with that understanding, were fully consistent with the Court's determination of the parties' understanding, agreement, and intent with regard to the MMQ at the time they executed the 2012 Agreement.

(e) <u>Source of Supply of Gypsum Filter Cake to Satisfy Section 3.1</u>

133. DEP contends that the MMQ must be read narrowly so as to limit its obligation to supply Gypsum Filter Cake to only supplying its production at the Roxboro Plant and Mayo Plant, whether or not that amount is less than the MMQ as the Court has found it to be defined by the 2012 Agreement.

134. The 2004 Agreement defined Gypsum Filter Cake as "a filter cake of calcium sulfate dehydrate, being a byproduct of the FGD Systems, which conforms to the Specifications." (Ex. 5 § 1.17.) FGD Systems were designated as "the Flue Gas Desulfurization system(s) to be installed, owned (in whole or in part) and operated by [DEP] at the Mayo and Roxboro Plants." (Ex. 5 § 1.14.)

135. DEP contends that these definitions, read together and considered in the context of the overall structure of the 2004 Agreement, demonstrate that the parties agreed that DEP was only obligated to supply synthetic gypsum produced from the FGD Systems at the Roxboro Plant and Mayo Plant.

136. The Court finds that such a narrow reading is inconsistent with other provisions adopted in the 2004 Agreement and carried forward in the 2008 Agreement and the 2012 Agreement. The parties repeatedly use the defined term "Gypsum Filter Cake" in a manner that makes clear that the reference must be to synthetic gypsum produced at locations other than the Roxboro Plant and Mayo Plant. (Ex. 15 §§ 3.8, 6.2.) The parties have consistently and repeatedly agreed that "[DEP's] expectation is to supply Gypsum Filter Cake *primarily* from the Roxboro and Mayo Plants, but retains the *right to supply Gypsum Filter Cake from any source.*") (Ex. 5 § 3.1; *see* Ex. 6 § 3.1; Ex. 15 § 3.1) (emphases added).) It is manifestly obvious that DEP could not obtain Gypsum Filter Cake from any source other than its Roxboro Plant and Mayo Plant if by definition any Gypsum Filter Cake must have been produced only at the Roxboro Plant or Mayo Plant.

137. The Court finds that the parties understood, intended, and agreed when entering into each of the Supply Agreements, that although DEP expected to supply synthetic gypsum primarily from its Roxboro Plant and Mayo Plant, it might be required to supply from other sources if necessary. DEP's pre-litigation course of action is fully consistent with their having so agreed.

(2) <u>Section 2.2.3 Regarding the Stockpile</u>

138. The Supply Agreements have consistently agreed that DEP would build and thereafter maintain a storage area on its property to store Gypsum Filter Cake at its Roxboro Plant. (*See* Ex. 5 § 2.2; Ex. 6 § 2.2.3(a); Ex. 15 § 2.2.3(a).) Before the CTG Plant was operational, DEP stored much of its production in the Stockpile, but

required CTG to remove amounts necessary to keep the Stockpile within a safe volume. The Supply Agreements contemplated that on an ongoing basis, so long as the Stockpile was within an acceptable volume, DEP may add Excess Gypsum to the Stockpile. (Ex. 5 § 1.12; Ex. 6 § 1.15; Ex. 15 § 1.21; *see* Ex. 5 § 2.2; Ex. 6 § 2.2.3(a); Ex. 15 § 2.2.3(a).)

139. The 2012 Agreement contains the following Section 2.2.3(a):

> [DEP] and CertainTeed have worked together to build a Gypsum Filter Cake stockpile (the "**Stockpile**") in the [DEP] Gypsum Storage Area. [DEP] will use *commercially reasonable efforts* to maintain at least 250,000 Net Dry Tons of Gypsum Filter Cake in the Stockpile at all times during the Term of this Revised Agreement. If the volume in the Stockpile falls below 250,000 Net Dry Tons, *[DEP] will be deemed to be using commercially reasonable efforts to maintain the required volume in the Stockpile as set forth herein to the extent that [DEP's] monthly production of Gypsum Filter Cake is used to fulfill its Minimum Monthly Requirement obligations as set forth herein, and (a) the Excess Gypsum is being utilized to replenish the Stockpile, or (b) to the extent otherwise agreed by the Operating Plan as provided below.* If at any time during the Term of this Revised Agreement the Stockpile falls below 250,000 Net Dry Tons or [DEP] has reason to believe that the Stockpile will fall below 250,000 Net Dry Tons for any reason . . . then (unless otherwise previously provided to CertainTeed) *[DEP] will provide a replenishment plan (the "**Replenishment Plan**") to CertainTeed to establish a plan to rebuild the volume in the Stockpile to 250,000 Net Dry Tons.*

(Ex. 15 § 2.2.3(a) (italics added).)

140. There is no evidence that the parties ever prepared the Operating Plan referred to in this section.

141. Section 2.2.3(b) details that CTG has responsibility for maintaining the conveyor that is used to transport materials from the Stockpile for delivery to the

CTG Plant and that CTG cannot allow the Stockpile to exceed 600,000 net dry tons of Gypsum Filter Cake, referred to as "the Storage Maximum." (Ex. 15 § 2.2.3(b).) Section 2.2.3(b) concludes with the following:

> For the avoidance of doubt, [DEP] will be deemed to have met its obligation hereunder to deliver its [MMQ] to the extent that [DEP] has delivered at least an aggregate total quantity of Gypsum Filter Cake at least equal to the [MMQ] (i) directly to the [CTG Plant] via the Gypsum Conveyor System, (ii) and/or to the [DEP] Gypsum Storage Area, and/or (iii) directly to the [CTG Plant] by truck if mutually agreed upon.

(Ex. 15 § 2.2.3(b).)

142. CTG contends that: (a) DEP is required to utilize commercially reasonable efforts to maintain the Stockpile at 250,000 Net Dry Tons of Gypsum Filter Cake; (b) DEP has failed to do so because it failed deliver the contractually required MMQ; (c) now that the Stockpile volume has fallen below 250,000 net dry tons, DEP is contractually obligated to produce a Replenishment Plan; and (d) the Replenishment Plan DEP has provided to date does not meet DEP's contractual obligation because it is not based on DEP's obligation to supply the MMQ throughout the term of the 2012 Agreement and seeks to impose on CTG the cost of now securing the volume necessary to replenish the Stockpile because of DEP's failures to supply the MMQ. (*See* Am. Compl. ¶¶ 102–03.)

143. DEP's contention revolves around its proposed definition of the MMQ. DEP contends that it has complied with its obligations under Section 2.2.3 because: (a) it has at all material times either delivered its entire production to CTG or added it to the Stockpile, and (b) it provided CTG with a Replenishment Plan, which DEP has followed. (*See* Ex. 54.)

144. The Court finds Section 2.2.3 of the 2012 Agreement to be ambiguous, requiring the Court to consider extrinsic evidence to determine the intent of the parties when entering the 2012 Agreement. The extrinsic evidence includes the drafting history of provisions regarding the Stockpile. The initial 2004 Agreement included a provision that DEP would "build and use reasonable efforts to maintain a 300,000 Net Dry Ton Gypsum Filter Cake [S]tockpile in the [DEP] Storage Area" and thereafter either dispose of Excess Gypsum or add it to the Stockpile. (Ex. 5 § 2.2.)

145. The 2008 Agreement reduced the minimum volume of the Stockpile to 250,000 Net Dry Tons of Gypsum Filter Cake, modified DEP's obligations from "reasonable efforts" to "commercially reasonable efforts," and added the requirement that DEP provide a Replenishment Plan if the Stockpile volume fell below 250,000 Net Dry Tons. (Ex. 6 § 2.2.3(a).) The parties also agreed in the 2008 Agreement that DEP, primarily at CTG's expense, would increase the Stockpile's storage capacity to 650,000 Net Dry Tons. (*See* Ex. 6 § 2.2.3(b).)

146. Section 2.2.3(a) of the 2012 Agreement closely tracked the section as it had been worded in the 2008 Agreement. DEP rejected Engelhardt's proposal that would have modified Section 2.2.3 to provide a Stockpile Buffer, which would guarantee that the Stockpile volume not be outside defined minimum and maximum volumes. (*See* Ex. 26 § 2.2.39(c).)

147. The parties presented little testimony regarding the specifics of the negotiations of the Stockpile provisions other than their testimony regarding Engelhardt's rejected proposal for the Stockpile Buffer.

148. The Court finds that, at the time they entered into the 2012 Agreement, the parties understood, intended, and agreed that: (a) DEP was required to exercise commercially reasonable efforts to maintain the Stockpile at a volume of at least 250,000 net dry tons of Gypsum Filter Cake; (b) DEP would be deemed to be using commercially reasonable efforts so long as it delivered the MMQ, unless otherwise excused, in the amount defined by Section 3.1 as the Court has found it to be and delivered in the manner defined by Section 2.2.3(b) of the 2012 Agreement; and (c) if DEP expected that the volume in the Stockpile would fall or had fallen below 250,000 net dry tons, it was required to prepare and provide to CTG a Replenishment Plan to rebuild the Stockpile.

149. It is undisputed that, at the time of trial, the Stockpile contained less than 250,000 tons of Gypsum Filter Cake. It is also undisputed that at all times since April 2017, when CTG and DEP's disagreement regarding the definition of the MMQ became apparent, DEP has used its entire production of synthetic gypsum at the Roxboro Plant and Mayo Plant either to deliver Gypsum Filter Cake to CTG or to add to the Stockpile.

150. On March 9, 2017, Weisker, on behalf of DEP, sent a letter to CTG informing it that the Stockpile would fall below 250,000 tons and that DEP was developing a Replenishment Plan. (Ex. 138.) DEP then prepared, and on July 25, 2017, supplied to CTG, a Replenishment Plan based on DEP's interpretation of the MMQ that it has promoted in this litigation, and which the Court has rejected. (*See* Ex. 54.)

151. While DEP has delivered Gypsum Filter Cake as its Replenishment Plan calls for, DEP has not, during the period after that Replenishment Plan was provided to CTG, consistently delivered the MMQ as the Court has found it to be. The evidence is clear that at least for certain months in 2017, after CTG timely demanded performance, DEP failed to deliver the MMQ as the Court has defined it to be for the 2012 Agreement. Accordingly, at least for those months, DEP has failed to use commercially reasonable efforts as defined by Section 2.2.3(a).

152. DEP has breached the 2012 Agreement by failing to prepare a Replenishment Plan consistent with this Opinion & Final Judgment and based on the MMQ as the Court has found it to be.

(3) <u>DEP's Defense Based on Section 3.9 and the Doctrine of Impossibility</u>

153. DEP contends that any performance obligation it may have undertaken in the 2012 Agreement is now excused by Section 3.9 of the 2012 Agreement, no matter what the Court determines the MMQ to be, because its further supply of Gypsum Filter Cake based on the 2012 Agreement terms and requirements is inconsistent with its Primary Purpose as a regulated utility. DEP relies on Section 3.9 of the 2012 Agreement, which reads:

> <u>Primary [DEP] Duty</u>. CertainTeed acknowledges and agrees that [DEP's] obligations hereunder are subject to [DEP's] overriding and primary duty to produce economical and reliable electric power for public consumption in accordance with federal, state[,] and local laws and regulations (the **"Primary Purpose"**) and nothing in this Revised Agreement shall, in any way, be interpreted or constructed so as to obligate [DEP] to attempt to maximize its production of synthetic gypsum, including without limitation, Gypsum Filter Cake and/or to operate any one or more of it Units and/or the FGD Systems and/or to

> change any of its processes in order to produce such synthetic gypsum or Gypsum Filter Cake at all or of a particular quality and/or form.

(Ex. 15 § 3.9; *see also* Ex. 6 § 3.9 (emphasis in original).)

154. CTG contends that all of the language of Section 3.9 must be read together and, when so read, Section 3.9 makes clear that DEP has no obligation to *produce* synthetic gypsum at the Roxboro Plant, Mayo Plant, or otherwise, but it does not excuse DEP from *supplying* Gypsum Filter Cake from whatever source is necessary to meet DEP's contractual obligation.

155. DEP contends that the language in Section 3.9 reflects two related but separate principles: first, that all of DEP's obligations under the 2012 Agreement are subservient to DEP's Primary Purpose, as expressed in the first clause in Section 3.9; and second, that the 2012 Agreement cannot be construed to compel DEP to "maximize its production of synthetic gypsum" to meet its supply obligation, as expressed in the second clause of Section 3.9. (*See* Ex. 15 § 3.9; *see also* Ex. 6 § 3.9.) DEP contends that the first clause expressing DEP's Primary Purpose has independent broad application adequate to excuse its further supply obligation.

156. As to Section 3.9, the Court has been able to determine the intent of the parties when they entered the 2012 Agreement based on that section's plain language. Section 3.9 clearly affirmatively represents, and reflects that CTG acknowledges, that DEP is a regulated utility company that must supply economical and reliable electricity consistent with law and regulations. (*See* Ex. 15 § 3.9.) Section 3.9 also clearly precludes CTG from demanding that DEP itself produce or maximize production of synthetic gypsum or Gypsum Filter Cake in any amount. It

does not follow that DEP is excused from its contractual supply obligation if complying with that obligation does not conflict with laws or regulations. If laws or regulations prohibit DEP from supplying Gypsum Filter Cake, an excuse afforded by Section 3.9 does not depend on whether DEP is producing Gypsum Filter Cake in any amount or at all. If no laws or regulations prohibit supplying Gypsum Filter Cake, DEP's supply obligation is not excused by Section 3.9, regardless of the amount of Gypsum Filter Cake DEP may be producing, if any.

157. There was no law or regulation restricting DEP's supply of Gypsum Filter Cake when the parties entered the 2012 Agreement. The Court finds, based on the plain language of Section 3.9, that the parties intended and agreed that Section 3.9 would excuse DEP from its obligation to supply synthetic gypsum if future changes in laws or regulations restrict DEP from supplying synthetic gypsum, but did not intend or agree that DEP would be excused if it could continue to lawfully supply its obligation, even if the expense of doing so increased to an unanticipated degree. DEP undertook an obligation to supply Gypsum Filter Cake, secured a contractual protection that its supply can come from alternate sources, and has offered no proof of any law or regulation that prohibits its supplying Gypsum Filter Cake. Experts for both parties agree there is no such law or regulation.

158. The Court must also read Section 3.9 in harmony with other provisions of the 2012 Agreement. Each of the Supply Agreements have included a force majeure article ("Force Majeure Article") that expressly provides that certain specific events will excuse either DEP's or CTG's performance obligations. Section 3.9

contains no similar express language. The Court finds no implied excuse arising from CTG's recognition that DEP's obligations are "subject to [DEP's] overriding and primary duty to produce economical and reliable electric power for public consumption in accordance with federal, state[,] and local laws." (Ex. 15 § 3.9.) The Court finds that Section 3.9 was not intended to provide that DEP could escape its supply obligations because changed circumstances may affect the economies of that supply. The Court concludes that the parties intended and agreed that any such changed circumstances, other than changes in law or regulation, would be addressed through the 2012 Agreement's remedy provisions in Article 6.

159. In sum, the Court reads the plain language of Section 3.9 to excuse DEP from its obligation to supply Gypsum Filter Cake only if it could no longer legally supply Gypsum Filter Cake. Section 3.9 does not support DEP's contention that it is no longer obligated to perform its supply obligation under the 2012 Agreement.

160. The Court has been able to determine the intent and meaning of Section 3.9 without resort to extrinsic evidence. However, the Court finds from the extrinsic evidence that it is fully consistent with the meaning the Court has determined from the plain contractual language.

(a) <u>Negotiating and Drafting Section 3.9</u>

161. Section 3.9 appeared for the first time during the drafting of the 2008 Agreement. Coppola, Mottola, and Morrow testified about the negotiations of the 2008 Agreement. Mottola and Coppola both testified that DEP considered Section

3.9 to be very important and non-negotiable. Morrow acknowledged that Section 3.9 was a new term, but he did not think it impacted the parties' performance obligations.

162. Coppola sent DEP's initial draft of the 2008 Agreement, which included Section 3.9, to CTG on November 22, 2007. (*See* Ex. 10.) Morrow sent a redlined draft back to Coppola on January 21, 2008, which included a comment immediately following Section 3.9 that stated—"This section is new. While the principle is probably acceptable, we will need to be careful that it does not upset [DEP's] minimum delivery obligations under the Agreement." (Ex. 10 § 3.9.) The evidence does not make clear who authored this comment, however, identifying the author is not critical to resolving the dispute between the parties because the Court's consideration of the comment is not a significant factor in its determination.

163. On February 14 and 15, 2008, the parties had a meeting to finalize the 2008 Agreement. After that meeting, Pam Larger, DEP's attorney, sent a working draft of the 2008 Agreement to CTG titled "Joint Discussion Draft." (Ex. 18.) DEP deleted the comment to Section 3.9 discussed above, but did not otherwise change the language of Section 3.9 from the earlier drafts. (*See* Ex. 18 § 3.9.) Neither Coppola nor Morrow recalled the specifics of any discussions about Section 3.9 during their February 2008 meeting.

164. Coppola testified that DEP intended Section 3.9 to provide it with broad protection, but she did not recall any specific discussions regarding Section 3.9. The Court finds Coppola's testimony to be significantly influenced by DEP's litigation position and is not persuaded that Coppola has any specific recollection of any

understanding between DEP and CTG as to the purpose and meaning of Section 3.9 other than what can be determined from its language alone.

165. Mottola testified to a more specific recollection of the contractual negotiations that led to the 2008 Agreement. The Court finds Mottola's overall testimony consistent with the Court's finding based on its plain reading of Section 3.9. Mottola explained that when negotiating the agreement, DEP could not predict what, if any, new laws or regulations might be enacted during the twenty-year contract term, thus it wanted protection from liability in the event that an unanticipated law or regulation prevented DEP from being able to supply Gypsum Filter Cake. Mottola acknowledged that DEP did not intend for Section 3.9 to excuse it from its performance obligations if a business decision or something unrelated to its compliance with a legal requirement impacted DEP's ability to supply Gypsum Filter Cake.

166. Mottola now offers his belief that DEP's compliance with the Least-Cost-Dispatch Requirement has resulted in DEP producing less synthetic gypsum at the Roxboro Plant and Mayo Plant, and that Section 3.9 excuses DEP's supply obligation. There is no evidence that, at the time the 2008 Agreement was entered, he or others contemplated or believed that such a scenario would excuse DEP's obligations to supply Gypsum Filter Cake.

167. Mottola recalls that Morrow expressed frustration with Section 3.9, believing that it might allow DEP to avoid its supply obligations, in response to which Mottola explained that DEP only intended for Section 3.9 to excuse it from its supply

obligation if there was a law or regulation that affected DEP's ability to supply Gypsum Filter Cake. Mottola admits that he never discussed with Morrow, or anyone else at CTG, that already-existing laws on the books could trigger Section 3.9.

168. Morrow did not recall any conversations with Mottola regarding Section 3.9 and testified that he understood Section 3.9 could not obligate DEP to produce synthetic gypsum, but that it did not affect DEP's obligation to supply Gypsum Filter Cake.

169. The Court finds that the greater weight of Mottola's testimony reflects the parties' intent at the time they executed the 2008 Agreement as the Court has found it to be.

170. The parties also offered evidence regarding negotiations of the Force Majeure Article, first adopted in the 2004 Agreement. During the drafting of the 2004 Agreement, Johnson added a paragraph to the Force Majeure Article that provided as follows:

> In construing and interpreting this Article 13 and other provisions of this Agreement, the parties shall recognize that the primary mission of the Roxboro Plant and the Mayo Plant shall be the safe production of electrical power on an economic basis [("Primary Mission")].

(Ex. 92 art. 13.) Johnson testified that he included this language because his managers instructed him to add it to the agreement but did not recall any further reason or discussion.

171. CTG deleted Johnson's proposed paragraph and provided a different paragraph that stated:

> In the event a change in a governmental law, rule or regulation, or an action or decision by [DEP], including without limitation, a decision to change fuel sources, affects the quality or quantity of Gypsum Filter Cake generated by [DEP] and [DEP] cannot meet its obligations under this Agreement, [CTG] shall have the remedies set forth in Sections 6.2 and 6.3 of this Agreement.

(Ex. 93 art. 13.)

172. DEP rejected CTG's proposal and reinserted the "Primary Mission" paragraph, which CTG accepted. Without further explanation from the parties, and in light of all other evidence, the Court finds that this proposed language and its omission from the final agreement neither supports nor detracts from the position of either party as to the meaning of Section 3.9 of the 2012 Agreement.

173. Significantly, while Section 12.1 of the 2012 Agreement lists several events that may excuse performance, DEP's Primary Mission is referenced in the separate Section 12.4, which does not expressly provide for excused performance. (Ex. 15 §§ 12.1, 12.4.) This distinction has been in place since the 2004 Agreement. (*See* Ex. 6 art. 12.)

174. The language of Section 3.9 was carried forward in the 2012 Agreement without significant negotiation or modification. There is no evidence that the parties intended to change the meaning or application of Section 3.9 when they executed the 2012 Agreement.

175. In sum, the Court finds that should it have been necessary to resort to extrinsic evidence to determine the intent of the parties as to the meaning of Section 3.9 when they entered the 2012 Agreement, the greater weight of the evidence is

consistent with the finding the Court has made based on its plain reading of Section 3.9 of the 2012 Agreement.

(b) <u>The Greater Weight of the Evidence Demonstrates that DEP's Supply Obligation is Neither Excused nor Impossible</u>

176. Eric Grant ("Grant"), DEP's Vice President of Fuels and Systems Optimization, explained how DEP currently operates its various plants and implements the Joint Dispatch Agreement consistent with its effort to comply with the regulatory Least-Cost-Dispatch Requirement. Based on that testimony and supporting documentation, the Court finds that DEP has operated its plants, including the Roxboro Plant and Mayo Plant, consistent with the Least-Cost-Dispatch Requirement since entering the 2012 Agreement. The Court further finds that, because of a decline in natural gas prices, the Least-Cost-Dispatch Requirement has resulted in DEP reducing operations of its coal-fired units, including the Roxboro Plant and Mayo Plant, resulting in a reduction of DEP's production of synthetic gypsum.

177. Current forecasts predict that that Least-Cost-Dispatch Requirement will, at least for the foreseeable future, continue to require reduced operations at the Roxboro Plant and Mayo Plant with a consequent continued reduced production of Gypsum Filter Cake at those plants in amounts that are inadequate to meet DEP's supply obligation under the 2012 Agreement.

178. The evidence also demonstrates that DEP will likely continue to produce at least some quantities of Gypsum Filter Cake at other coal-fired plants, which either it or its affiliated companies operate.

179. The evidence does not allow any long-range prediction of how fuel prices may vary going forward, and how changes, if any, will impact plant utilization. It is then unclear how future changes in fuel prices may affect DEP's Economic Dispatch during the remaining term of the 2012 Agreement.

180. Evidence demonstrates that DEP has been able either to transport Gypsum Filter Cake from other plants or purchase it from affiliate companies. While there is evidence of significant expense necessary to transport Gypsum Filter Cake from alternative sources, there is no evidence supporting a finding that supplying Gypsum Filter Cake from other sources is now or expected to be impossible.

181. Both parties presented testimony from expert witnesses. CTG offered expert testimony from Ms. Gisele Rankin ("Rankin"), a former attorney on the public staff of the North Carolina Utilities Commission, who was accepted, without objection from DEP, as an expert on the subject of utility regulation in North Carolina. DEP offered expert testimony from Kim Smith ("Smith"), a Rates & Regulatory Strategy Director with Duke Energy, who was tendered, without objection from CTG, as an expert on the utilities laws, rules, and regulations that apply to DEP. Both Rankin and Smith agree that the decreased cost of natural gas has resulted in the Roxboro Plant and Mayo Plant falling lower in the Economic Dispatch order, and, as a result, the Roxboro Plant and Mayo Plant are producing less synthetic gypsum.

182. Rankin proffered that DEP's reduced production of synthetic gypsum is, in part, caused by its decision to enter into the Joint Dispatch Agreement with DEC. The Court finds this to be speculative, and that the more probative evidence from

Grant suggests that it is more likely that DEP has operated its coal-fired plants more frequently than it would have had it not entered the Joint Dispatch Agreement.

183. Rankin and Smith both agree that there are no laws or regulations that prohibit DEP from purchasing synthetic gypsum from third parties or affiliates. Smith did not opine that DEP's obligation to supply Gypsum Filter Cake under the 2012 Agreement was inconsistent with DEP's Primary Purpose at the time it entered into that agreement. To the contrary, she concurred that, although DEP is not in the business of brokering the supply of synthetic gypsum, synthetic gypsum is a byproduct with which DEP must deal, and it entered into the Supply Agreements to provide a beneficial reuse for that byproduct—an undertaking that was a part of, and consistent with, DEP's Primary Purpose of producing reliable and economical electricity.

184. Rankin and Smith offered testimony regarding the potential as to whether the North Carolina Utilities Commission will allow DEP to recover any costs it may incur as a result of meeting its supply obligations under the 2012 Agreement. The Court finds it unnecessary to determine or opine on what the Commission might allow.

185. Although there have been changes in the factual circumstances, the laws and regulations that defined DEP's Primary Purpose remain as they were when DEP executed the Supply Agreements. The Least-Cost-Dispatch Requirement existed long before the parties executed the Supply Agreements.

186. The Court finds that there has been no change of circumstance, either in fact or law, that prohibits or excuses DEP from supplying Gypsum Filter Cake pursuant to the 2012 Agreement. The Court finds that Section 3.9 does not excuse DEP from meeting its supply obligation and that it is not impossible for DEP to meet its supply obligation as defined by the 2012 Agreement.

(4) <u>Section 6.2 and Section 6.3—Remedies Available to CTG for DEP's Failure to Meet Supply Obligations</u>

187. Since 2004, Article 6 in the Supply Agreements has included distinct paragraphs that define the parties' remedies as follows: (1) Defective Material; (2) Undersupply by [DEP] ("Section 6.2"); (3) Discontinued Supply by [DEP] ("Section 6.3"); (4) Under Acceptance by [CTG] ("Section 6.4"); and (5) Discontinued Acceptance by [CTG] ("Section 6.5"). (*See* Ex. 5 §§ 6.1–6.5; *see also* Ex. 6 §§ 6.1–6; Ex. 15 §§ 6.1–6.) Section 9.4 of each of the Supply Agreements provides that "[w]here a remedy is specified in this Revised Agreement for a particular breach or occurrence, the remedy specified shall be the sole and exclusive remedy for the breach or occurrence, whether arising in contract, tort (including negligence), strict liability or otherwise." (Ex. 5 § 9.4; Ex. 6 § 9.4; Ex. 15 § 9.4.)

188. The parties both seek a declaratory judgment regarding the meaning and interpretation of Section 6.3, and specifically whether it becomes CTG's exclusive remedy once it is triggered by certain actions taken by DEP. Section 6.3 provides that once DEP takes certain actions, CTG may terminate the 2012 Agreement and recover liquidated damages. While the parties agree that DEP has not yet taken the

actions that may trigger Section 6.3, they agree that their dispute as to the Section's meaning is of immediate importance and justifies the Court's declaration.

189. The primary dispute regarding remedies is this: DEP contends that once triggered, CTG's termination remedy is exclusive; CTG contends that it continues throughout the 2012 Agreement to have an election between termination and specific performance. Stated otherwise, DEP contends that if there are acts that constitute a "discontinued supply," in contrast to an "undersupply," then termination with liquidated damages is CTG's sole remedy. CTG contends that a "discontinued supply" is only a variant of an "undersupply," and the remedies for the two are not mutually exclusive.

190. Section 6.2 of the 2012 Agreement, titled "Undersupply by [DEP]," provides in significant part that

> [s]ubject to the quantity variations permitted under Section 2.2 and 3.1, in the event [DEP] is unable to deliver to [CTG] the [MMQ] in any month during the term of this Revised Agreement and such failure is not excused under the terms and conditions of this Revised Agreement, [CTG] may, at its election, by written notice to [DEP] within thirty (30) days after the end of the month in which the deficiency occurred, either (a) instruct [DEP] in writing to deliver within thirty (30) days at [DEP's] sole expense to the Point of Delivery the quantity of Gypsum Filter Cake necessary to satisfy the [MMQ], or (b) purchase on the open market on a commercially reasonable basis for delivery to the [CTG Plant], the amount of Gypsum Filter Cake necessary to satisfy the lesser of [CTG's] commercial requirements or the [MMQ].

(Ex. 15 § 6.2.) Section 6.2 further provided that CTG may recover the cover price in excess of the contract price. (Ex. 15 § 6.2.)

191. In net effect, Section 6.2 provides that, unless DEP's monthly supply obligation is excused, if DEP fails to deliver the MMQ for any month, then CTG, upon

proper notice, can either demand that DEP deliver the MMQ or obtain DEP's supply obligation on the market and recover its cover expenses. CTG waives its Section 6.2 remedy for any month in which it fails to provide timely written notice of default. (Ex. 15 § 6.2; *see also* Ex. 6 § 6.2.)

192. Section 6.3 of the 2012 Agreement, titled "Discontinued Supply by [DEP]," provides in significant part that

> [if DEP] (a) elects to discontinue altogether supplying Gypsum Filter Cake to CertainTeed; (b) takes any action that prevents or will prevent [DEP] from supplying at least fifty percent (50%) of the Minimum Monthly Quantity each month over a five (5) year period, or (c) takes any other action that causes [DEP] to supply 300,000 Net Dry Tons or less Gypsum Filter Cake per year in two (2) consecutive Contract Years, CertainTeed may terminate this Revised Agreement, and if this Revised Agreement is terminated pursuant to this Section, [DEP] shall pay to CertainTeed as liquidated damages upon written request annual payments for the remainder of the Initial Term . . . equal to the Minimum Monthly Quantity multiplied by the current price of Gypsum Filter Cake then in effect under this Revised Agreement plus [an agreed-upon dollar amount], multiplied by the number of months in that year remaining in this Revised Agreement.

(Ex. 15 § 6.3.) The Court will refer to the three actions specified by Section 6.3 as "Discontinuance Events."

193. Sections 6.4 and 6.5 respectively provide DEP remedies for CTG's "under acceptance" and for CTG's "discontinued acceptance." Section 6.4 provides that, for any month in which CTG fails to accept the MMQ, DEP may recover the cost incurred to dispose of any amount of the MMQ that CTG does not accept. (*See* Ex. 15 § 6.4.) Section 6.5 provides that DEP may terminate the 2012 Agreement if CTG takes action defined as discontinued acceptance. If terminating on this basis, DEP has the election between recovering liquidated damages or requiring CTG to transfer

title to the CTG Plant along with the facilities and intellectual property necessary to operate the plant. (Ex. 15 § 6.5.)

194. Having considered the parties' positions, the Court finds that Section 6.2 and Section 6.3 are ambiguous, requiring the Court to consider extrinsic events to determine the parties' intent when entering the 2012 Agreement.

(a) Drafting History

195. The relevant provisions of Article 6 were first negotiated and agreed to in the 2004 Agreement. The parties then carried forward the remedies sections from the 2004 Agreement to the 2008 Agreement and then again to the 2012 Agreement without significant negotiation or modification.[2] Although some witnesses involved in the negotiations of the 2008 Agreement generally recalled discussions about the remedies provisions, there is no dispute that Article 6 remained substantially unchanged after the parties executed the 2004 Agreement and carried it forward through the 2008 Agreement, and eventually to the 2012 Agreement.

196. CTG prepared the first draft agreement that began the negotiation process that led to the 2004 Agreement. College sent Johnson the first draft of a proposed agreement on May 12, 2003. (*See* Ex. 90.) This draft included remedies for CTG but did not provide remedies for DEP. (*See* Ex. 90 art. 6.) In this draft, CTG drafted two separate untitled paragraphs under the general heading "Remedies for

[2] The only substantial changes to Section 6.2 and Section 6.3 from the 2004 Agreement to the 2012 Agreement are that Section 6.3 in the 2012 Agreement is no longer triggered by DEP failing to build its FGD Systems, (*see* Ex. 5 § 6.3(a)), and the language of 6.2 was modified to reflect the changes made to Section 3.1 in the 2008 Agreement to eliminate the Start-Up Period. (*Compare* Ex. 5 § 6.2, *with* Ex. 15 § 6.2.) These changes do not affect the current dispute as to whether the Section 6.3 remedy is exclusive once triggered.

[CTG]." (Ex. 90 § 6.1.) Section 6.1(a) provided that if DEP failed to deliver the MMQ in any given month, then CTG could, on a month-to-month basis, either demand that DEP deliver the MMQ or make purchases on the open market and recover its cover expenses from DEP. (Ex. 90 § 6.1(a); *see also* Ex. 91 § 6.2(a).) Section 6.1(b) addressed specific actions taken by DEP that would materially interrupt DEP's supply over a sustained period, and specified that DEP was required to give two years' advance notice prior to taking such action, and thereafter pay CTG liquidated damages. (Ex. 90 § 6.1(b); *see also* Ex. 91 § 6.2(b).)

197. CTG's initial draft included a provision that the remedies in Article 6 "are, and shall be the sole and exclusive remedies for [CTG] with respect to the subject matter contained therein." (Ex. 90 § 6.2.)

198. Although the wording later changed, CTG's concept of distinct remedies for a short-term monthly undersupply and a long-term disruption of supply became the structure around which the final Article 6 was drafted. CTG's initial draft provisions were the foundation of what became the final Article 6, as well as Section 9.4.

199. DEP provided no written draft in response to CTG's initial draft. CTG's counsel, Mark Lontchar, edited the initial draft that College sent Johnson on May 27, 2003. (*See* Ex. 91.) This revised draft added remedies for DEP while not changing CTG's remedies, and modified the exclusive remedies provision to make it applicable to both DEP and CTG. (*See* Ex. 91 §§ 6.1, 6.2.)

200. Johnson sent DEP's markup of CTG's second draft to College on July 24, 2003 ("July 2003 Draft"). (*See* Ex. 92.) The July 2003 Draft introduced the headings of "Undersupply by [DEP]," "Discontinued Supply by [DEP]," "Under Acceptance by [CTG]," and "Discontinued Acceptance by [CTG]" that were ultimately included in Article 6 of the 2004 Agreement and added the exclusive remedies provision that became Section 9.4. (Ex. 92 §§ 6.2–6.5, 10.3; *see* Ex. 5 §§ 6.2–6.5, 9.4.)

201. DEP deleted CTG's proposed language that would require DEP to provide two years' advance notice of action that would lead to a discontinued supply. CTG did not later propose an alternative advance notice requirement.

202. Johnson testified that DEP separated CTG's remedies for DEP's non-performance into two sections because DEP believed that undersupply and discontinued supply were two separate events that required different remedies. Likewise, DEP separated remedies for CTG's under-acceptance and discontinued acceptance into two distinct sections. (*See* Ex. 92 §§ 6.4–6.5.)

203. Mayer and Johnson both testified that they discussed the types of short-term operational issues that would possibly trigger Section 6.2, including routine maintenance and equipment failure. Johnson explained that DEP intended Section 6.2 to be the sole remedy for non-recurring, short-term events and Section 6.3 to be the sole remedy for long-term, forward-looking events that led DEP to decide to either discontinue supplying Gypsum Filter Cake or take an action that would severely hinder its ability to supply Gypsum Filter Cake.

204. Mayer agreed that the parties intended Section 6.2 to address short-term variations in supply caused by business-operational issues. He testified that Section 6.3 was intended to address a decision by DEP to either completely cut off supply of Gypsum Filter Cake or that resulted in a substantial interruption in DEP's ability to supply Gypsum Filter Cake.

205. The Court finds that the greater weight of the testimony and documentary evidence is that Mayer and Johnson both recognized a distinction between short-term failures in supply or acceptance caused by events that could be remedied quickly, and long-term business decisions by either CTG or DEP that would cause long-term disruptions in either CTG's ability to accept or DEP's ability to supply synthetic gypsum, and that Mayer and Johnson intended to draft remedies that recognized this distinction.

206. On August 25, 2003, CTG sent DEP a draft that added the words "continuously" and "may terminate" into Section 6.3, stating "[i]n the event DEP. . . (ii) takes any action that materially and substantially diminishes [DEP's] ability to *continuously* supply Gypsum Filter Cake in sufficient quantities to meet the [MMQ] . . . [CTG] *may terminate this Agreement* and [DEP] shall pay to [CTG] . . . a termination fee . . . ." (Ex. 93 § 6.3 (emphasis added).) Ultimately, when adopted, both Section 6.3 and Section 6.5 provided that the party "may terminate" rather than providing the termination was automatic. While the term "continuously" was not expressly incorporated into Section 6.3 and Section 6.5, at least some of the events

described in these sections addressed disruptions in supply or acceptance that continue over a significant period. (Ex. 5 §§ 6.3, 6.5.)

207. Mayer testified that CTG proposed the word "continuously" to emphasize that the actions that would trigger Section 6.3 "represented an extreme condition of undersupply." (Tr. 341:2–3; *see also* Tr. 340:24–341:7.) Mayer testified that the "may terminate" language was added to Section 6.3 to clarify that CTG has the option but not the obligation to terminate under Section 6.3. (Tr. 341:11–13; Ex. 93 § 6.3; Ex. 97 § 6.3.) Mayer testified that CTG wanted the flexibility "to continue running the plant and seek gypsum from [DEP] instead of terminating." (Tr. 307: 17–18.) Johnson understood that the intent of this modification was to provide that the termination remedies were not self-executing, but rather would require the non-defaulting party to take an action to trigger the termination remedy.

208. Mayer further testified to his current view that, at the time the parties executed the 2004 Agreement, he believed that if CTG elected not to terminate the agreement under Section 6.3, then CTG could continue to invoke its remedies under Section 6.2 throughout the remaining term of the 2012 Agreement, even after events triggering Section 6.3 occurred. He offered the position CTG has advanced in the litigation that the triggering events of Section 6.3 are also an undersupply within the meaning of Section 6.2, so that CTG should have remedies under both provisions for the entire contract term. Johnson testified to the opposite and indicated that DEP would not have agreed to such a result. There is no testimony or documentary evidence that indicates that either Mayer, Johnson, or others involved in the

negotiation of the 2004 Agreement ever discussed a belief that the "may terminate" language CTG proposed was intend to allow CTG to elect between a termination for a discontinued supply or a specific performance remedy for a continuing undersupply.

209. The greater weight of the evidence is that both parties intended specific and separate remedies for the separate and distinct events of undersupply or under acceptance on the one hand, and discontinued supply or discontinued acceptance on the other hand, and that once the remedy of termination with liquidated damages was triggered by DEP's taking action defined by Section 6.3, that remedy became CTG's exclusive remedy of the breach of discontinuing supply. The Court further finds from the greater weight of the evidence that until the Discontinuance Events occur, CTG may enforce its remedy under Section 6.2 for those months in which DEP has failed to supply the contractual MMQ, and although Section 6.3 becomes exclusive when triggered, that exclusive remedy does not retroactively extinguish remedies CTG had under Section 6.2.

210. The Court finds that the parties intended that the termination remedy would not be mandatory. As Mayer testified, CTG intended to provide CTG an opportunity to assess its options once events triggered a potential termination. The Court finds that the parties understood that, while termination was not mandatory upon a Discontinuance Event, they did understand and agree that a Discontinuance Event would afford the non-defaulting party a right to terminate and would displace all other remedies for that discontinuance, including any right to demand specific performance as to earlier defaults from month to month.

211. The Court therefore finds that CTG's assertion that it will have a continuing right to exercise Section 6.2 remedies throughout the remaining term of the 2012 Agreement even if DEP takes action that constitutes a Discontinuance Event is not supported by, and is inconsistent with, the greater weight of the evidence as to the intent of the parties both at the time the 2004 Agreement was negotiated and at all times thereafter, including when entering the 2012 Agreement.

212. The Court finds that the parties recognized when drafting the remedies under Article 6 of the 2004 Agreement, that they were entering into a prospective twenty-year agreement with uncertain risks, and that, during the course of the term of that agreement, circumstances might compel either party to discontinue its performance. The parties did not agree or intend to preclude such a discontinuance, but provided that any such discontinuance would expose the defaulting party to termination and liquidated damages determined pursuant to a formula first adopted in the 2004 Agreement and carried forward in the 2008 Agreement and the 2012 Agreement.

213. The Court's findings are consistent with the manner and reason that CTG proposed adding the "may" language to Section 6.3. The Court finds that there is no evidence to support CTG's position that adding "may" in Section 6.3 was intended to provide CTG with the right to elect between the remedies provided in Section 6.2 and Section 6.3 throughout the 2012 Term.

214. In sum, the Court finds that the parties intended, understood, and agreed that if DEP takes an action defined as a Discontinuance Event under Section

6.3 of the 2012 Agreement, Section 6.3 will then provide CTG's sole remedy, but until DEP takes such an action, CTG can pursue its remedies under Section 6.2 on a month-to-month basis for any DEP short-term undersupply that is not otherwise excused.

G. CTG is Entitled to Recover Under Section 6.2 for DEP's Breaches to Date that Have Not Been Waived

215. In early 2017, Halm consulted legal counsel when he concluded that the Stockpile would fall below a volume of 250,000 net dry tons. After speaking with counsel, Halm changed his understanding regarding DEP's obligations to supply Gypsum Filter Cake under the 2012 Agreement.

216. CTG's and DEP's representatives met on April 5, 2017, and DEP advised CTG, for the first time, that it believed that the amendment to Section 3.1 in the 2012 Agreement had changed the MMQ to a variable quantity that could fall below 50,000 net dry tons per month based on DEP's production at its Roxboro Plant and Mayo Plant. There is no evidence that CTG was aware or had reason to believe prior to that meeting that DEP interpreted the MMQ in this manner, despite the fact that the amounts actually delivered or accepted under the 2012 Agreement had varied from month to month.

217. The evidence demonstrates that for a number of months after April 2017, DEP has not supplied the MMQ as the Court has found it to be under the 2012 Agreement.

218. The Court finds that DEP breached Section 3.1 of the 2012 Agreement by failing to deliver the MMQ, less acceptable fluctuations defined by Section 3.1, for

the months of May 2017, June 2017, and September 2017 through January 2018. In those months, DEP based its delivery on its definition of the MMQ that the Court has rejected. For each of those months, CTG provided the notice required by Section 6.2 and demanded that DEP deliver the deficient amount of Gypsum Filter Cake. (*See* Ex. 115.)

219. After notice, DEP did not deliver the shortfall between the MMQ and its actual delivery.

220. CTG and DEP entered into an agreement whereby, for those months, DEP sold and delivered, and CTG purchased and accepted, Gypsum Filter Cake from alternative sources at prices that were in excess of the contract price pursuant to the MMQ, but in accordance with the price set for Other Gypsum as defined by the 2012 Agreement. (*See* Ex. 15 § 3.6). CTG reserved its right to recover what it contends were excess payments.

221. DEP delivered Gypsum Filter Cake to CTG in May 2017, June 2017, and September 2017–January 2018 as follows:

Month	**Tonnage**
May 2017	36,252.97
June 2017	27,547.96
September 2017	34,865.82
October 2017	40,080.01
November 2017	38,006.52
December 2017	31,656.60

January 2018	21,822.09

(*See* Factual Stipulations, Ex. 1.)

222. The Court finds that for these months, CTG was entitled to receive and DEP was obligated to deliver at the contract price the MMQ, less acceptable fluctuations as defined by Section 3.1. Because of DEP's supply failure, CTG failed to receive the entire MMQ.

223. Between May 2017 and January 2018, CTG purchased 59,925.17 net dry tons of synthetic gypsum from DEP directly or from its affiliate in order to supplement the volumes that DEP delivered, and paid greater than the MMQ contract price. (Factual Stipulations ¶¶ 4–12; *see also* Ex. 176.) The parties have stipulated as to the amount CTG paid in excess of the MMQ contract price.

V. CONCLUSIONS OF LAW

224. Based on the foregoing Findings of Fact, the Court makes the following Conclusions of Law.

225. The Court has jurisdiction over the parties and the subject matter of this action.

226. The case was properly designated as a mandatory complex business case and assigned to the undersigned, who has authority to make Findings of Fact following the completion of the trial and the submission of all disputed issues for resolution by the Court without a jury.

227. Any Findings of Fact that are more appropriately deemed Conclusions of Law are incorporated by reference as the Court's Conclusions of Law.

228. There is a real and existing controversy as to the terms and enforcement of the 2012 Agreement, and the Court's declaration is necessary to settle the legal rights and duties of the parties to the 2012 Agreement.

229. The 2012 Agreement is a fully enforceable contract, and at the time the parties entered into the 2012 Agreement, they mutually agreed to all of its material and essential terms, including but not limited to Section 2.2.3, Section 3.1, Section 3.9, Section 6.2, Section 6.4, Section 9.4, and Section 12.4.

230. When entering the 2012 Agreement, the parties were not mistaken as to any term of the 2012 Agreement, either as to law or fact, in any manner that renders any provision of the 2012 Agreement unenforceable, either by mutual or unilateral mistake, or a failure to agree.

231. Although certain terms and provisions of the 2012 Agreement are ambiguous, the Court, considering extrinsic evidence where necessary, is able to discern the intent of the parties at the time they entered the 2012 Agreement.

232. As to Section 3.9 of the 2012 Agreement, the Court concludes that its meaning can be determined from the plain language of the agreement. Having considered the extrinsic evidence offered by the parties, the Court further concludes that the greater weight of that extrinsic evidence is consistent with the Court's finding based on Section 3.9's plain language.

233. The Court concludes that the provisions of Sections 2.2.3, 3.1, 6.2, 6.3, and 9.4 of the 2012 Agreement are ambiguous and the Court cannot determine the meaning of these disputed sections from the plain language of the 2012 Agreement,

so that it is appropriate that the Court consider extrinsic evidence as to those sections to determine the intent of the parties when entering the 2012 Agreement.

234. Although the Court has considered only extrinsic evidence regarding negotiations prior to entering the 2012 Agreement to resolve any ambiguity as to the intent of the parties when entering the 2012 Agreement, after having heard evidence offered as to the course of performance from the time the parties entered the agreement to the time the litigation began, the Court finds that the greater weight of that evidence is consistent with the Court's interpretation of the disputed provisions of the 2012 Agreement, specifically its quantity term defined as the MMQ.

235. Based on the Findings of Fact stated above, the Court concludes, declares, and decrees that:

a. As used in the 2012 Agreement, the term MMQ means 50,000 Net Dry Tons of Gypsum Filter Cake;

b. Unless otherwise excused or extinguished, for the remainder of the 2012 Term, DEP is contractually obligated to supply and CTG is contractually obligated to accept the MMQ, subject to the minor fluctuations permitted under Section 3.1;

c. When entering the 2012 Agreement, the parties intended and agreed that their respective obligations to supply or accept Gypsum Filter Cake pursuant to Section 3.1 would be satisfied so long as (1) DEP delivered and CTG accepted between 45,000 to 55,000 net dry tons of Gypsum Filter Cake per month; and (2) over a twelve-month period, DEP delivered and CTG accepted the lesser of 600,000 net dry tons of Gypsum Filter Cake or the aggregate actual production of synthetic gypsum at the Roxboro Plant and Mayo Plant, with the net effect that DEP was required to deliver and CTG was required to accept between 540,000 and 600,000 net dry tons of Gypsum Filter Cake over a twelve-month period;

d. The definition of Gypsum Filter Cake as used in the 2012 Agreement is not limited to Gypsum Filter Cake produced at DEP's Roxboro Plant and Mayo Plant;

e. When entering the 2012 Agreement, the parties intended and agreed that DEP may be required to meet its supply obligation by acquiring Gypsum Filter Cake from alternative sources if its production at its Roxboro Plant and Mayo Plant is not adequate to fulfill that obligation;

f. Section 3.9 does not excuse DEP's supply obligation under the 2012 Agreement because DEP's further supply obligation is not inconsistent with its Primary Purpose;

g. There is no current law or regulation that makes it unlawful for DEP to supply CTG with Gypsum Filter Cake from whatever source necessary;

h. DEP's supply obligation under the 2012 Agreement has not been excused by any Force Majeure;

i. It is not impossible for DEP to meet its supply obligation under the 2012 Agreement, and that supply obligation is not excused by the doctrine of impossibility;

j. DEP is required to use commercially reasonable efforts to maintain the Stockpile at 250,000 net dry tons of Gypsum Filter Cake;

k. If the Stockpile volume falls below 250,000 net dry tons, DEP will be deemed to be using commercially reasonable efforts if it (1) delivers the MMQ each month, as provided by Section 2.2.3(b) of the 2012 Agreement; and (2) places Excess Gypsum, if any, on the Stockpile until the volume is restored to 250,000 net dry tons;

l. The volume of the Stockpile has fallen below 250,000 net dry tons, obligating DEP to prepare and deliver to CTG a Replenishment Plan to restore the Stockpile to 250,000 net dry tons;

m. DEP has breached the 2012 Agreement because the Replenishment Plan earlier delivered to CTG by DEP, (Ex. 54), did not satisfy DEP's obligation under the 2012 Agreement to provide a Replenishment Plan consistent with the MMQ supply and acceptance obligations the Court has determined in this Opinion & Final Judgment;

n. In the event that DEP takes any of those actions defined in Section 6.3 of the 2012 Agreement as a Discontinued Supply by DEP, such action will constitute a breach of DEP's supply obligation under the 2012 Agreement, providing CTG the option but not the obligation to terminate the agreement and recover liquidated damages pursuant to Section 6.3;

o. If DEP takes action that constitutes a "Discontinued Supply" as defined in Section 6.3, CTG will have the option but not the obligation to exercise this remedy; however, in that event, Section 6.3 shall provide CTG's exclusive remedy for DEP's failure to supply Gypsum Filter Cake after taking such actions; and

p. CTG continues to have the right to pursue its Section 6.2 remedies for any DEP supply failure occurring prior to DEP's taking action that constitutes a Discontinued Supply as defined by Section 6.3.

236. Except as declared above, any further request by either party for declaratory relief is denied.

237. DEP has failed to carry its burden of proof on its defenses.

238. There is no factual or legal basis that bars CTG's remedies by application of the doctrines of unclean hands, waiver, or estoppel.

239. DEP breached its obligation to supply the MMQ of 50,000 net dry tons per month, subject to fluctuations permitted by Section 3.1 of the 2012 Agreement,

for the months of May 2017, June 2017, and September 2017–January 2018. CTG provided the required notice and is entitled to its remedies under Section 6.2 of the 2012 Agreement.

240. CTG is entitled to recover from DEP that amount paid in excess of the contract price as stipulated in Exhibit 176, together with interest until paid.

241. DEP is obligated at its own expense to deliver to CTG such additional amounts as may be necessary to meet its supply obligation for the months of May 2017, June 2017, and September 2017–January 2018. Each party has requested that it be awarded its costs and attorneys' fees. The Court concludes that any consideration of this collateral issue should be deferred.

BASED ON THE FOREGOING FINDINGS OF FACT AND CONCLUSIONS OF LAW, IT IS HEREBY ORDERED THAT:

1. DEP shall pay to CTG the stipulated amount stated in Exhibit 176 as payments CTG has made in excess of the contract price, together with interest until paid;
2. DEP shall, within thirty days of this Opinion & Final Judgment, at the contract price, deliver as CTG directs, such amounts of Gypsum Filter Cake as are necessary to fulfill its obligations to supply the MMQ less acceptable minor fluctuations for the months of May 2017, June 2017, and September 2017–January 2018, and less amounts already accepted by CTG;

3. DEP shall within ninety days of this Opinion & Final Judgment provide CTG with a Replenishment Plant prepared consistent with the MMQ as the Court has defined it in this Opinion & Final Judgment;

4. In the absence of a timely appeal, any party that seeks to recover its costs and attorneys' fees pursuant to Section 16.7 of the 2012 Agreement shall file its motion, accompanied by a brief and supporting materials, within forty-five days of the date of this Opinion & Final Judgment;

5. In the event of a timely appeal, any party that seeks to recover its costs and attorneys' fees pursuant to Section 16.7 of the 2012 Agreement shall file its motion, accompanied by a brief and supporting materials, within thirty days of the final mandate of the highest appellate court;

6. Notwithstanding the reservation of the collateral issue of costs and attorneys' fees, this Opinion & Final Judgment is intended to be and is a final judgment in all respects pursuant to North Carolina Rule of Civil Procedure 54.

SO ORDERED, this the 28th day of August, 2018.

/s/ James L. Gale

James L. Gale
Senior Business Court Judge

-/A

LI Exhibit 1
Schedule 1

Duke Energy Progress, LLC
Docket No. E-2, Sub 1204
North Carolina Annual Fuel and Fuel-Related Expense
Proposed Nuclear Capacity Factor of 94.62%
SUMMARY OF PUBLIC STAFF FUEL AND FUEL RELATED COST FACTORS
Test Period Twelve Months Ended March 31, 2019
Billing Period December 1, 2019 - November 30, 2020

Line No.	Description	Reference	Residential cents/KWh	Small General Service cents/KWh	Medium General Service cents/KWh	Large General Service cents/KWh	Lighting cents/KWh
	Current Fuel and Fuel-Related Cost Factors (Approved Fuel Rider Docket No. E-2, Sub 1173)						
1	Approved Fuel and Fuel-Related Costs Factors	Sub 1173 Order Appendix A	2.311	2.556	2.477	1.757	2.251
2	EMF Increment / (Decrement)	Sub 1173 Order Appendix A	0.575	0.363	0.343	1.038	0.885
3	EMF Interest Decrement cents/kWh, if applicable	n/a	-	-	-	-	-
4	Approved Net Fuel and Fuel-Related Costs Factors	Sum of Lines 1 through 3	2.886	2.919	2.820	2.795	3.136
	Company Proposed Fuel and Fuel Related Cost Factors						
5	Fuel and Fuel-Related Costs excluding Purchased Capacity cents/kWh	L7 - L6	2.206	2.372	2.345	1.977	2.280
6	Total of Renewable and Cogeneration Purchased Power Capacity	Revised Harrington Exhibit 2, Sch 1, Page 2	0.138	0.155	0.123	0.079	0.001
7	Total adjusted Fuel and Fuel Related Costs cents/kWh	L10 - L8 - L9	2.344	2.527	2.468	2.056	2.281
8	EMF Increment (Decrement) cents/kWh	Revised Harrington Exhibit 3, Pages 2 - 6	0.394	0.217	0.236	0.666	0.548
9	EMF Interest Decrement cents/kWh, if applicable	n/a	-	-	-	-	-
10	Net Fuel and Fuel Related Costs Factors cents/kWh	Revised Harrington Exhibit 2, Sch 1, Page 2	2.738	2.744	2.704	2.722	2.829
	Public Staff Proposed Fuel and Fuel Related Cost Factors						
11	Fuel and Fuel Related Costs excluding Purchased Capacity cents/kWh	L13 - L12	2.188	2.344	2.333	1.975	2.216
12	Purchased Power - Capacity cents/kWh	Revised Harrington Exhibit 2, Sch 1, Page 2	0.138	0.155	0.123	0.079	0.001
13	Total adjusted Fuel and Fuel Related Costs cents/kWh	L16 - L14 - L15	2.326	2.499	2.456	2.054	2.217
14	EMF Increment (Decrement) cents/kWh	LI Exhibit 1, Schedules 3-1 through 3-5	0.373	0.198	0.218	0.648	0.530
15	EMF Interest Decrement cents/kWh	n/a	-	-	-	-	-
16	Net Fuel and Fuel Related Costs Factors cents/kWh	LI Exh 1, Sch 2	2.699	2.697	2.674	2.702	2.747
	Differences between the Public Staff's and the Company's Proposed Fuel Related Cost Factors						
17	Fuel and Fuel Related Costs excluding Purchased Capacity cents/kWh	L11 - L5	(0.018)	(0.028)	(0.012)	(0.002)	(0.064)
18	Purchased Power - Capacity cents/kWh	L12 - L6	-	-	-	-	-
19	Total adjusted Fuel and Fuel Related Costs cents/kWh	Sum of L17 & L18	(0.018)	(0.028)	(0.012)	(0.002)	(0.064)
20	EMF Increment (Decrement) cents/kWh	L14 - L8	(0.021)	(0.019)	(0.018)	(0.018)	(0.018)
21	EMF Interest Decrement cents/kWh	L15 - L9	-	-	-	-	-
22	Net Fuel and Fuel Related Costs Factors cents/kWh	Sum of Lines 19 through 21	(0.039)	(0.047)	(0.030)	(0.020)	(0.082)

Note: The above rates do not include state regulatory fees.
Effective July 1, 2019, the Regulatory Fee rate changed from 0.14% to 0.13%.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1204
North Carolina Annual Fuel and Fuel Related Expense
PUBLIC STAFF COMPUTATION OF UNIFORM PERCENTAGE AVERAGE BILL ADJUSTMENT BY CUSTOMER CLASS
Proposed Nuclear Capacity Factor of 94.62% and Projected Billing Period MWh Sales
Billing Period December 1, 2019 - November 30, 2020

LJ Exhibit 1
Schedule 2

Line No.	Rate Class	Projected Billing Period MWh Sales		Annual Revenue at Current rates		Allocate Fuel Costs Increase/(Decrease) to Customer Class	Increase/Decrease as % of Annual Revenue at Current Rates	Total Fuel Rate Increase/(Decrease) cents/kwh	Current Total Fuel Rate (including renewables and EMF) E-2, Sub 1173 cents/kwh	Proposed Total Fuel Rate (including renewables and EMF) cents/kwh
		A		B		C	D	E	F	G
		Workpaper 8		Workpaper 11		Line 27 as a % of Column B	C / B	If C=0 then 0 if not then (C*100)/(A*1000)	Exhibit 1, Line 4	E + F = G
1	Residential	18,265,079	$	1,838,488,040	$	(30,473,562)	-1.6%	(0.187)	2.886	2.699
2	Small General Service	1,806,876		249,548,540		(4,005,826)	-1.6%	(0.222)	2.919	2.697
3	Medium General Service	10,414,506		950,513,824		(15,257,163)	-1.6%	(0.146)	2.820	2.674
4	Large General Service	9,223,825		534,744,328		(8,583,443)	-1.6%	(0.093)	2.795	2.702
5	Lighting	381,171		92,439,556		(1,483,793)	-1.6%	(0.389)	3.136	2.747
6	NC Retail	38,091,457	$	3,725,734,287	$	(59,803,587)				

Line No.	Description	Source			Amount	
	Public Staff Proposed Composite Fuel Rate for the Billing Period:					
7	Adjusted System Total Fuel Costs excluding system-wide $8.4M Liquidated Damages Cost to CTG	Workpaper 8		$	1,424,636,845	1/
8	System Renewable and Qualifying Facilities Purchased Power Capacity	Revised Harrington Exhibit 2 Page 2	Sch 1,		74,415,842	
9	Adjusted System Other Fuel Costs	Line 7 - Line 8		$	1,350,221,003	
10	NC Retail Allocation % - sales at generation	Workpaper 10			61.68%	
11	NC Retail Other Fuel Costs excluding NC's $5.2M Liquidated Damages Cost to CTG.	Line 9 * Line 10		$	832,816,315	1/, 2/
12	NC Renewable and Qualifying Facilities Purchased Power Capacity	Revised Harrington Exhibit 2 Page 2	Sch 1,		45,394,250	
13	NC Retail Total Fuel Costs before 2.5% Purchase Power Test	Line 11 + Line 12		$	878,210,565	
14	NC Retail Reduction due to 2.5% Purchased Power Test	Workpaper 16			0	
15	NC Retail Total Fuel Costs	Line 13 + Line 14		$	878,210,565	
16	NC Projected Billing Period MWh Sales	Line 6, col A			38,091,457	
17	Calculated Fuel Rate cents/kWh	Line 15 / Line 16 / 10			2.306	
18	Proposed Composite EMF Rate cents/kWh				0.381	
19	Proposed Composite EMF Rate Interest cents/kWh	0			0.000	
20	Total Proposed Composite Fuel Rate	Sum of Lines 17-19			2.687	
	Total Current Composite Fuel Rate - Docket E-2 Sub 1173:					
21	Current composite Fuel Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 17			2.242	
22	Current composite EMF Rate cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 18			0.602	
23	Current composite EMF Interest cents/kWh	2018 Ward Exhibit 2, Sch 1, Pg 3, Ln 19			0.000	
24	Total Current Composite Fuel Rate	Sum of Lines 21-23			2.844	
25	Increase/(Decrease) in Composite Fuel rate cents/kWh	Line 20 - Line 24			(0.157)	
26	NC Projected Billing Period MWh Sales	Line 6, col A			38,091,457	
27	Increase/(Decrease) in Fuel Costs	Line 25 * Line 26 * 10		$	(59,803,588)	

1/ Based on testimony of Public Staff witness Jay B. Lucas.
2/ Based on the Direct Testimony of Harrington, Page 12.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1204
North Carolina Annual Fuel and Fuel Related Expense
PUBLIC STAFF COMPUTATION of Experience Modification Factor - Proposed Composite
Test Period Twelve Months Ended March 31, 2019

Li Exhibit 1
Schedule 3

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	Reported (Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.515	2.280	2,821,410	$ 6,616,553	-	$ 6,616,553
2	May	2.794	2.286	2,743,729	13,930,507	-	13,930,507
3	June	2.884	2.277	3,379,527	20,501,107	-	20,501,107
4	July	2.641	2.275	3,687,027	13,504,786	-	13,504,786
5	August	2.619	2.277	3,705,569	12,651,306	-	12,651,306
6	September	2.954	2.276	3,324,420	22,555,310	-	22,555,310
7	October	2.142	2.282	3,247,434	(4,537,212)	-	(4,537,212)
8	November	2.768	2.286	2,905,623	14,008,619	-	14,008,619
9	December (New Rates - Sub 1173)	4.223	2.256	2,853,152	56,124,620	-	56,124,620
10	January 2019	2.845	2.250	3,344,813	19,890,481	$ (33,252)	19,857,229
11	February	0.978	2.256	3,239,879	(41,422,510)	-	(41,422,510)
12	March	2.714	2.248	2,793,993	13,007,082	-	13,007,082
13	Total Test Period			38,046,575	$ 146,830,650	$ (33,252)	$ 146,797,398
14	April	2.686	2.236	2,728,574	12,291,799		12,291,799
15	May	2.782	2.239	2,833,194	15,364,636		15,364,636
16	June	2.680	2.249	3,213,527	13,827,917		13,827,917
17	Total 15-month Test Period			46,821,871	188,315,002	(33,252)	188,281,750
18	Booked (Over) / Under Recovery						$ 188,281,750
19	Coal Inventory Rider (Over) / Under Recovery						257,250
20	Company Adjustment to remove by-product net gain/loss accrued expense						(44,144,639)
21	Company Adjustment to include by-product net gain/loss cash payments						6,640,945
22	Public Staff Adjustment to remove by-product net gain/loss cash payments						(6,640,945) 1/
23	Public Staff Adjustment to remove by-product net gain/loss/judgment payment						(619,200) 1/, 2/
24	Total (Over) / Under Recovery						$ 143,775,161
25	Normalized Test Period MWh Sales	Exhibit 4					37,693,746
26	Experience Modification Increment / (Decrement) cents/KWh						0.381

1/ Based on testimony of Public Staff witness Jay B. Lucas.
2/ Li Exhbit 4.

Li Exhibit 1
Schedule 3-1

Duke Energy Progress, LLC
Docket No. E-2, Sub 1204
North Carolina Annual Fuel and Fuel Related Expense
PUBLIC STAFF COMPUTATION of Experience Modification Factor - Residential
Test Period Twelve Months Ended March 31, 2019

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.501	2.179	1,138,012	$ 3,660,529		$ 3,660,529
2	May	3.023	2.179	1,016,135	8,577,706		8,577,706
3	June	2.787	2.179	1,404,775	8,539,907		8,539,907
4	July	2.467	2.179	1,586,631	4,574,733		4,574,733
5	August	2.510	2.179	1,553,969	5,138,198		5,138,198
6	September	2.811	2.179	1,404,365	8,874,465		8,874,465
7	October	2.193	2.179	1,264,650	179,201		179,201
8	November	2.995	2.179	1,072,132	8,748,809		8,748,809
9	December (New Rates - Sub 1173)	3.604	2.237	1,386,673	18,956,228		18,956,228
10	January 2019	2.682	2.311	1,552,025	5,751,516	$ (14,440)	5,737,076
11	February	0.899	2.311	1,553,478	(21,931,387)		(21,931,387)
12	March	2.733	2.311	1,214,159	5,128,001		5,128,001
13	Total Test Period			16,147,005	$ 56,197,905	$ (14,440)	$ 56,183,465
14	April	3.033	2.311	1,060,985	7,664,663		7,664,663
15	May	3.295	2.311	1,051,096	10,340,265		10,340,265
16	June	2.843	2.311	1,331,074	7,081,848		7,081,848
17	Total 15-month Test Period			19,590,161	81,284,681	(14,440)	$ 81,270,241
18	Booked (Over) / Under Recovery						$ 81,270,241
19	Coal inventory Rider (Over) / Under Recovery						107,665
20	Company Adjustment to remove by-product net gain/loss accrued expense						(21,280,626)
21	Company Adjustment to include by-product net gain/loss cash payments						3,041,510
22	Public Staff Adjustment to remove by-product net gain/loss cash payments						(3,041,510) 1/
23	Public Staff Adjustment to remove by-product net gain/loss/judgment payment						(261,574) 1/, 2/
24	Total (Over) / Under Recovery						$ 59,835,706
25	Normalized Test Period MWh Sales	Exhibit 4					16,022,203
26	Experience Modification Increment (Decrement) cents/KWh						0.373

1/ Based on testimony of Public Staff witness Jay B. Lucas.
2/ Li Exhibit 4.

Li Exhibit 1
Schedule 3-2

Duke Energy Progress, LLC
Docket No. E-2, Sub 1204
North Carolina Annual Fuel and Fuel Related Expense
PUBLIC STAFF COMPUTATION of Experience Modification Factor - Small General Service
Test Period Twelve Months Ended March 31, 2019

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.289	2.121	140,607	$ 236,079		$ 236,079
2	May	2.535	2.121	136,871	567,097		567,097
3	June	2.480	2.121	178,846	642,201		642,201
4	July	2.281	2.121	194,597	310,810		310,810
5	August	2.231	2.121	198,191	217,119		217,119
6	September	2.489	2.121	179,772	662,100		662,100
7	October	1.789	2.121	174,119	(578,233)		(578,233)
8	November	2.312	2.121	156,234	298,658		298,658
9	December (New Rates - Sub 1173)	4.862	2.313	120,842	3,080,272		3,080,272
10	January 2019	2.969	2.556	174,110	718,822	$ (1,763)	717,059
11	February	1.095	2.556	159,655	(2,332,952)		(2,332,952)
12	March	2.847	2.556	144,886	421,865		421,865
13	Total Test Period			1,958,731	$ 4,243,838	$ (1,763)	$ 4,242,075
14	April	2.930	2.556	136,059	508,889		508,889
15	May	2.974	2.556	144,225	603,324		603,324
16	June	2.793	2.556	167,849	397,399		397,399
17	Total 15-month Test Period			2,406,864	5,753,449	(1,763)	$ 5,751,686
18	Booked (Over) / Under Recovery						$ 5,751,686
19	Coal Inventory Rider (Over) / Under Recovery						13,266
20	Company Adjustment to remove by-product net gain/loss accrued expense						(1,888,719)
21	Company Adjustment to include by-product net gain/loss cash payments						333,054
22	Public Staff Adjustment to remove by-product net gain/loss cash payments						(333,054) 1/
23	Public Staff Adjustment to remove by-product net gain/loss/judgment payment						(33,484) 2/
24	Total (Over) / Under Recovery						$ 3,842,749
25	Normalized Test Period MWh Sales	Exhibit 4					1,941,728
26	Experience Modification Increment (Decrement) cents/KWh						0.198

1/ Based on testimony of Public Staff witness Jay B. Lucas.
2/ Li Exhbit 4.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1204
North Carolina Annual Fuel and Fuel Related Expense
PUBLIC STAFF COMPUTATION of Experience Modification Factor - Medium General Service
Test Period Twelve Months Ended March 31, 2019

Li Exhibit 1
Schedule 3-3

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)	
1	April 2018 (Sub 1146)	2.440	2.356	834,634	$ 700,759		$ 700,759	
2	May	2.524	2.356	871,652	1,468,210		1,468,210	
3	June	2.683	2.356	1,042,496	3,411,985		3,411,985	
4	July	2.601	2.356	1,074,969	2,629,373		2,629,373	
5	August	2.536	2.356	1,098,143	1,980,830		1,980,830	
6	September	2.852	2.356	988,512	4,902,428		4,902,428	
7	October	1.955	2.356	1,021,065	(4,091,099)		(4,091,099)	
8	November	2.453	2.356	940,892	913,230		913,230	
9	December (New Rates - Sub 1173)	5.035	2.409	706,334	18,544,231		18,544,231	
10	January 2019	3.287	2.477	883,889	7,155,890	$ (9,828)	7,146,062	
11	February	1.127	2.477	855,202	(11,548,986)		(11,548,986)	
12	March	2.927	2.477	790,364	3,557,351		3,557,351	
13	Total Test Period			11,108,152	$ 29,624,202	$ (9,828)	$ 29,614,374	
14	April	2.697	2.477	827,811	1,817,211		1,817,211	
15	May	2.639	2.477	908,898	1,474,141		1,474,141	
16	June	2.710	2.477	967,184	2,251,604		2,251,604	
17	Total 15-month Test Period			13,812,044	35,167,158	(9,828)	$ 35,157,330	
18	Booked (Over) / Under Recovery						$ 35,157,330	
19	Coal Inventory Rider (Over) / Under Recovery						75,961	
20	Company Adjustment to remove by-product net gain/loss accrued expense						(11,042,950)	
21	Company Adjustment to include by-product net gain/loss cash payments						1,830,267	
22	Public Staff Adjustment to remove by-product net gain/loss cash payments						(1,830,267)	1/
23	Public Staff Adjustment to remove by-product net gain/loss/judgment payment						(184,118)	1/, 2/
24	Total (Over) / Under Recovery						$ 24,006,222	
25	Normalized Test Period MWh Sales	Exhibit 4					11,007,307	
26	Experience Modification Increment (Decrement) cents/KWh						0.218	

1/ Based on testimony of Public Staff witness Jay B. Lucas.
2/ Li Exhibit 4.

Li Exhibit 1
Schedule 3-4

Duke Energy Progress, LLC
Docket No. E-2, Sub 1204
North Carolina Annual Fuel and Fuel Related Expense
PUBLIC STAFF COMPUTATION of Experience Modification Factor - Large General Service
Test Period Twelve Months Ended March 31, 2019

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)
1	April 2018 (Sub 1146)	2.709	2.417	678,418	$ 1,978,810		$ 1,978,810
2	May	2.886	2.417	689,394	3,230,432		3,230,432
3	June	3.476	2.417	723,936	7,668,586		7,668,586
4	July	3.135	2.417	801,315	5,754,642		5,754,642
5	August	3.034	2.417	825,198	5,091,306		5,091,306
6	September	3.504	2.417	723,070	7,861,222		7,861,222
7	October	2.406	2.417	757,387	(84,221)		(84,221)
8	November	2.971	2.417	707,153	3,914,585		3,914,585
9	December (New Rates - Sub 1173)	4.582	2.125	610,753	15,002,143		15,002,143
10	January 2019	2.603	1.757	704,241	5,960,860	$ (7,072)	5,953,788
11	February	0.937	1.757	643,138	(5,275,468)		(5,275,468)
12	March	2.371	1.757	615,274	3,776,307		3,776,307
13	Total Test Period			8,479,278	$ 54,879,204	$ (7,072)	$ 54,872,132
14	April	2.086	1.757	674,418	2,215,935		2,215,935
15	May	2.160	1.757	699,442	2,816,304		2,816,304
16	June	2.297	1.757	718,601	3,877,285		3,877,285
17	Total 15-month Test Period			10,571,739	63,788,728	(7,072)	$ 63,781,656
18	Booked (Over) / Under Recovery						$ 63,781,656
19	Coal Inventory Rider (Over) / Under Recovery						57,952
20	Company Adjustment to remove by-product net gain/loss accrued expense						(9,490,349)
21	Company Adjustment to include by-product net gain/loss cash payments						1,376,227
22	Public Staff Adjustment to remove by-product net gain/loss cash payments						(1,376,227) 1/
23	Public Staff Adjustment to remove by-product net gain/loss/judgment payment						(134,678) 1/, 2/
24	Total (Over) / Under Recovery						$ 54,214,580
25	Normalized Test Period MWh Sales	Exhibit 4					8,368,542
26	Experience Modification Increment (Decrement) cents/KWh						0.648

1/ Based on testimony of Public Staff witness Jay B. Lucas.
2/ Li Exhibit 4.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1204
North Carolina Annual Fuel and Fuel Related Expense
PUBLIC STAFF COMPUTATION of Experience Modification Factor - Lighting
Test Period Twelve Months Ended March 31, 2019

Li Exhibit 1
Schedule 3-5

Line No.	Month	Fuel Cost Incurred ¢/ kWh (a)	Fuel Cost Billed ¢/ kWh (b)	NC Retail MWh Sales (c)	(Over)/Under Recovery (d)	Adjustments (e)	Adjusted (Over)/Under Recovery (f)	
1	April 2018 (Sub 1146)	1.793	1.657	29,739	$ 40,376		$ 40,376	
2	May	1.950	1.657	29,677	87,063		87,063	
3	June	2.466	1.657	29,473	238,428		238,428	
4	July	2.454	1.657	29,516	235,228		235,228	
5	August	2.401	1.657	30,068	223,853		223,853	
6	September	2.546	1.657	28,700	255,094		255,094	
7	October	1.780	1.657	30,213	37,141		37,141	
8	November	2.113	1.657	29,213	133,338		133,338	
9	December (New Rates - Sub 1173)	3.817	1.919	28,549	541,747		541,747	
10	January 2019	3.244	2.251	30,547	303,393	$ (149)	303,244	
11	February	1.076	2.251	28,406	(333,718)		(333,718)	
12	March	2.673	2.251	29,310	123,557		123,557	
13	Total Test Period			353,410	$ 1,885,501	$ (149)	$ 1,885,352	
14	April	2.541	2.251	29,301	85,101		85,101	
15	May	2.693	2.251	29,533	130,603		130,603	
16	June	3.014	2.251	28,819	219,780		219,780	
17	Total 15-month Test Period			441,063	2,320,986	(149)	$ 2,320,837	
18	Booked (Over) / Under Recovery						$ 2,320,837	
19	Coal Inventory Rider (Over) / Under Recovery						2,406	
20	Company Adjustment to remove by-product net gain/loss accrued expense						(441,994)	
21	Company Adjustment to include by-product net gain/loss cash payments						59,886	
22	Public Staff Adjustment to remove by-product net gain/loss cash payments						(59,886)	1/
23	Public Staff Adjustment to remove by-product net gain/loss/judgment payment						(5,346)	1/, 2/
24	Total (Over) / Under Recovery						$ 1,875,903	
25	Normalized Test Period MWh Sales	Exhibit 4					353,965	
26	Experience Modification Increment (Decrement) cents/KWh						0.530	

1/ Based on testimony of Public Staff witness Jay B. Lucas.
2/ Li Exhibit 4.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1204
Public Staff Adjustment to Test Period Fuel Expenses
For the Test Period Ended March 31, 2019

Line No.	Item	Percent		NC Retail Amounts	
1	Judgment Payment			$ 619,200	1/
2	Total Adjustment to Decrease Fuel Expenses			$ 619,200	
	Rate Class Allocations:	Percent		Amount	
3	Residential	42.244%	2/	261,574	To Li Exhibit 1 Schedules 3-1 through 3-5.
4	Small General Service	5.408%	2/	33,484	
5	Medium General Service	29.735%	2/	184,118	
6	Large General Service	21.750%	2/	134,678	
7	Lighting	0.863%	2/	5,346	
8	Total	100.000%		619,200	

1/ Based on the Company's response to Public Staff DR13-12.
2/ Based on the allocation of the MWH for each class for September 2018 divided by Total MWH Sales for September 2018.

Coppola Halm I/-
Public Staff – Cross 1
Exhibit 1

NORTH CAROLINA PERSON COUNTY	IN THE GENERAL COURT OF JUSTICE SUPERIOR COURT DIVISION 17 CVS 395
CERTAINTEED GYPSUM NC, INC., Plaintiff, v. DUKE ENERGY PROGRESS, LLC, Defendant.	**AFFIDAVIT OF GISELE L. RANKIN**

Gisele L. Rankin, being duly sworn, hereby deposes and says:

1. I am over the age of 21 and I am competent to make this affidavit.

2. I received a B.A. degree in 1977 from the University of North Carolina at Chapel Hill and a Juris Doctor degree, with honors, in 1980 from the University of North Carolina School of Law.

3. I was previously employed as a senior Staff Attorney with the Public Staff of the North Carolina Utilities Commission (the "Commission"). I served on the Public Staff for almost thirty-four (34) years, retiring on April 1, 2015.

4. For the last 20 years, my work has focused on electricity issues before the Commission. I was extensively involved in proceedings involving energy-related merger applications; affiliate transactions, least cost integrated resource planning proceedings, general rate cases; avoided cost rates and contract terms and conditions; certificates of public convenience and necessity (particularly with respect to renewable energy); and interconnection issues.

5. I have also been involved in electricity-related proceedings before the Federal Energy Regulatory Commission.

6. Upon retirement, I was conferred The Order of the Long Leaf Pine by the State of North Carolina, and I received the 2015 Lifetime Achievement Award from the North Carolina Sustainable Energy Association and the 2015 Energy Leadership Lifetime Achievement Award from Energy Inc. Summit and the Charlotte Business Journal.

7. I currently serve on the committee of the North Carolina State Bar Board of Legal Specialization that established utility law as a specialization in 2016, and I have been recognized as a Board-certified specialist in Utility Law.

8. I have reviewed the Complaint, Amended Complaint, Defendant's Answer, Defendant's Responses to Plaintiff's First Interrogatories, Plaintiff's Motion for Summary Judgment, Defendant's Response to the Plaintiff's Motion for Summary Judgment and the other documents of record filed in *CertainTeed Gypsum NC, Inc., v. Duke Energy Progress, LLC,* Case No. 17 CVS 395.

9. I have reviewed and am familiar with the Second Amended and Restated Supply Agreement dated August 1, 2012 entered into between CertainTeed Gypsum NC, Inc. ("CTG") and Duke Energy Progress, LLC, as successor by merger to Carolina Power & Light Company ("Duke Progress") (the "2012 Supply Agreement").

SUMMARY OF CONCLUSIONS

10. I understand Duke Progress's position in this case to be that Section 3.9 of the 2012 Supply Agreement excuses its obligations to perform pursuant to the terms of the agreement. Specifically, I understand Duke Progress's contention to be that (1) because Duke Progress has an obligation under Chapter 62 of the North Carolina General Statutes and Commission regulations to provide economical and reliable power and (2) because it is now more economical to produce electricity by burning natural gas than coal (which produces synthetic gypsum as a byproduct),

Duke Progress is not required to provide synthetic gypsum at the levels called for in the 2012 Supply Agreement.

11. While I agree that Duke Progress, as a public utility, has an obligation to provide economical and reliable power for public consumption and that currently it is more economical to produce electricity by burning natural gas than coal, I disagree that either of those facts relieves Duke Progress from any of its obligations under the 2012 Supply Agreement.

12. Under the 2012 Supply Agreement, Duke Progress is not obligated to provide the synthetic gypsum due CTG from its Roxboro and Mayo coal-burning power plants. Section 3.1 of the contract specifically provides that Duke Progress retains the right to supply that gypsum from any source. Furthermore, as Duke Progress acknowledges in its discovery responses, it and its affiliate, Duke Energy Carolinas, LLC ("Duke Carolinas"), are producing synthetic gypsum at several other coal-fired power plants in North Carolina. As discussed below, while there are Commission regulations addressing the financial terms of transfers between Duke Progress and its affiliates, there is no prohibition on such transfers.

DUKE'S OBLIGATIONS UNDER THE 2012 SUPPLY AGREEMENT

13. Under the 2012 Supply Agreement, Duke Progress agreed to sell and deliver to CTG synthetic gypsum each month for an initial term of twenty (20) years, from May 1, 2009 to May 1, 2029.

14. I understand that the parties have a dispute regarding the meaning of Section 3.1 of the 2012 Supply Agreement and whether the parties intended the Minimum Monthly Quantity of Synthetic Gypsum to be delivered by Duke Progress and accepted by CTG to be 50,000 net tons or some other amount.

15. While the 2012 Supply Agreement states that Duke Progress expects that the primary supply of synthetic gypsum to be delivered by it to CTG would come from Duke Progress's Roxboro and Mayo Plants, Sections 3.1 and 3.3.1 specifically recognize that Duke Progress can meet its monthly obligation by delivering synthetic gypsum to CTG from alternative sources.

16. Section 3.9 of the 2012 Supply Agreement provides that Duke Progress's obligations under the contract are subject to Duke Progress's overriding and primary duty to produce economical and reliable electric power for public consumption in accordance with federal, state and local laws and regulations, and nothing in the 2012 Supply Agreement shall be construed to obligate Duke Progress to maximize its production of synthetic gypsum.

LEAST COST ECONOMIC DISPATCH

17. Duke Progress argues that Section 3.9 of the 2012 Supply Agreement excuses its failure to perform under the 2012 Supply Agreement, due to its overriding obligation to operate its plants in accordance with least cost order of dispatch principles. Duke Progress says that because natural gas prices are less than coal prices, it is required to meet demand by running its natural gas burning plants before it runs its coal-burning plants. While Duke Progress is right about the current cost of natural gas and coal and right that this makes it cost effective to change the dispatch order of the plants and burn natural gas before burning coal, those things are irrelevant to Duke Progress's obligations to supply synthetic gypsum to CTG under the 2012 Supply Agreement.

18. According to the Commission's *Annual Report to the Joint Legislative Commission on Governmental Operations on the Long-Range Needs for Expansion of Electric Expansion Facilities*, dated December 2016, actual power plant use by public utilities is determined by the application of least cost economic dispatch principles, meaning that the start-up, shutdown, and level

of operation of individual generating units is tied to the incremental cost incurred to serve specific loads so that the most cost-effective production of electricity is attained.

19. Economic dispatch can be described as turning on (or ramping up) power generating facilities in the order of their operating costs (lowest to highest) as power demand grows throughout each day.

20. Factors such as startup costs; the increase in maintenance costs if plants are started up and shut down more than certain amounts; transmission outages, particularly unexpected outages; and fuel supply issues can all cause generating facilities to be operated out of order.

21. Currently, the low cost of natural gas as a fuel and the efficiency of newer gas-fired combined cycle generating facilities have caused Duke Progress's Roxboro and Mayo coal-burning plants to be turned on (dispatched) later in the order of dispatch than they were dispatched in past years. This has been exacerbated by the fact that, following the implementation of joint dispatch as a result of the merger of Progress Energy, Inc., and Duke Energy Corporation, the more efficient coal plants owned by Duke Carolinas are dispatched sooner, causing the Roxboro and Mayo plants to be pushed to even later positions in the dispatch order.

UTILITIES COMMISSION REGULATORY AUTHORITY

22. North Carolina General Statute § 62-2(a) provides that the rates, services and operations of public utilities are affected with the public interest and that the availability of an adequate and reliable supply of electric power and natural gas to the people, economy and government of North Carolina is a matter of public policy.

23. In furtherance of this public policy, the Commission is vested with the statutory authority to regulate public utilities generally, their rates, services and operations, and their expansion in relation to long-term energy conservation and management policies and statewide

development requirements. Chapter 62 of the North Carolina General Statutes, which is the chapter that contains North Carolina's Public Utilities Act, explicitly states that nothing therein is to be construed to imply any extension of Commission jurisdiction over any industry or enterprise that is not subject to the regulatory jurisdiction of the Commission. N.C. Gen. Stat. § 62-2(b).

24. Furthermore, notwithstanding the authority of the Commission to regulate its service and rates, and other matters incidental thereto, the property of a public utility is private property and the business is private business. *State ex rel. Utilities Commission v. General Tel. Co. of Southeast*, 281 N.C. 318, 189 S.E.2d 705 (1972). The fact that a business is a public utility does not make every service performed or rendered by it a public service subject to regulation and oversight by the Commission. A public utility is free to manage its property and business as it sees fit and the Commission may not restrict or control a public utility in the acquisition of property or the price paid for it. *Halifax Paper Co. v. Roanoke Rapids Sanitary Dist.*, 232 N.C. 421, 429, 61 S.E.2d 378, 384 (1950).

25. The Commission has no regulatory jurisdiction over any industry or enterprise that is not a public utility, including CTG. While the Commission sets a public utility's rates on the basis of whether its costs are reasonable and prudently incurred, the Commission does not directly regulate that public utility's purchase of raw materials or any other products, the transportation of raw materials or any other products, or the sale or other disposition of materials generated during the power generation process, including synthetic gypsum.

26. The Commission has the authority to disallow costs for ratemaking purposes when appropriate, but it does not have the authority to abrogate a third-party contract that does not deal with the provision of public utility service or the rate that is paid for such service.

27. To my knowledge, there are no Commission regulations or statutes in Chapter 62 that would prohibit Duke Progress from purchasing synthetic gypsum from third parties and transporting such synthetic gypsum to Roxboro, North Carolina, for delivery to CTG. There also are no Commission regulations or statutes in Chapter 62 that would prohibit Duke Progress from transporting synthetic gypsum to Roxboro from its Asheville coal-fired plant. In sum, there are no Commission-related requirements or prohibitions that would keep Duke Progress from fulfilling its contractual obligations to CTG or excuse Duke Progress's performance of that agreement.

28. In hindsight, the forecasted price of natural gas, the changes wrought by the implementation of joint dispatch, and the effects of both of these on the production of synthetic gypsum at the Roxboro and Mayo Plants should have been considered more seriously by Duke Progress at the time it entered into the 2012 Supply Agreement. The fact that it made a bad bargain is a business risk it took, and neither Chapter 62 nor the Commission's rules and regulations require or allow Duke Progress to get out of the agreement. It may turn out that Duke Progress is treated for ratemaking purposes as if it had lower costs or higher profits associated with the sale of synthetic gypsum under the agreement, but, again, there is no provision in North Carolina regulatory law that requires or allows Duke Progress to abrogate the agreement and escape its obligations to a private third-party.

THE PURCHASE OF SYNTHETIC GYPSUM FROM AFFILIATES

29. Duke Progress acknowledges in its discovery responses that it is producing synthetic gypsum at its Asheville coal-fired plant. It also acknowledged that it has the ability to bring synthetic gypsum to its Roxboro Plant for delivery to CTG from coal-fired plants owned by its affiliates, including the Allen, Belews Creek, Cliffside, and Marshall Plants belonging to Duke Carolinas, the Crystal River Plant belonging to Duke Energy Florida, LLC, and the Cayuga and

Gibson Plants belonging to Duke Energy Indiana, LLC. *See* Defendant's Response to Plaintiff's First Set of Interrogatories, Resp. No. 10. With the exception of the Asheville Plant which is owned by Duke Progress, each plant identified by Duke Progress as an alternate source of synthetic gypsum is owned by an affiliate of Duke Progress.

30. Just as there is no regulatory prohibition under Commission rules and regulations or otherwise that would prohibit Duke Progress from purchasing synthetic gypsum from a third party and transporting it to Roxboro, North Carolina, for delivery to CTG, there is no regulatory prohibition under Commission rules and regulations or otherwise that would prohibit Duke Progress from purchasing the same from an affiliate and transporting it to Roxboro for delivery to CTG.

31. While the Commission has adopted regulatory conditions governing affiliate transactions in merger proceedings through the years, these rules allow Duke Progress to purchase from the utility affiliates listed in paragraph 29 above at cost. Thus, while the financial terms of an affiliate transaction made by a public utility may be regulated, such transactions are not prohibited.

32. In the Commission's most recently adopted merger conditions approved in in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682, *in the Matter of Application of Duke Energy Corporation and Piedmont Natural Gas, Inc., to Engage in a Business Combination Transaction and Address Regulatory Conditions and Code of Conduct*, Regulatory Condition 5.2(a) provides as follows (emphasis added):

> DEC [Duke Carolinas], DEP [Duke Progress], and Piedmont each shall seek out and buy all goods and services from the lowest cost qualified provider of comparable goods and services, and shall have the burden of proving that any and all goods and services procured from their Utility Affiliates, Non-Utility Affiliates, and Nonpublic Utility Operations **have been procured on terms and conditions comparable to the most favorable terms and conditions reasonably available in the relevant market,** which shall include a showing that comparable goods or services could not have been procured at a lower price from qualified non-Affiliate sources or that

> DEC, DEP, or Piedmont could not have provided the services or goods for itself on the same basis at a lower cost. ...

34. This same condition further provides that to the extent the Commission approves the procurement or provision of goods and services between or among DEC, DEP, Piedmont, and the Utility Affiliates, those goods and services may be provided at the supplier's cost (as defined by the conditions), which is an exception to the otherwise required market pricing.

35. Thus, while there are provisions governing the price at which goods or services are provided or procured between affiliates, those rules do not bar Duke Progress from entering into affiliate transactions, including the purchase of synthetic gypsum from the Allen, Belews Creek, Cliffside, Marshall, Crystal River, Cayuga, and Gibson Plants owned by its affiliates.

FURTHER AFFIANT SAYETH NOT.

Gisele L. Rankin

Gisele L. Rankin

Sworn to and subscribed before me this the 21st day of January, 2018.

[Official Seal]

LAURA TWINE
NOTARY PUBLIC
WAKE COUNTY, N.C.

Laura Twine

Notary Public/Commissioner of Oaths Signature

Laura Twine

Printed Name

My Commission Expires: 6/26/20

CERTIFICATE OF SERVICE

This certifies that I have this day electronically filed the foregoing document with the North Carolina Business Court which will serve the foregoing in accordance with B.C.R 3.9(a):

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This the 29th day of January, 2018.

/s/ Brian C. Fork
Brian C. Fork

-/A

Metz

EXHIBIT 1

Proposed Fuel and Fuel-Related Cost Factors in cents per kWh effective December 1, 2019
(excludes regulatory fee)

TABLE 1 – Company PROPOSED Fuel and Fuel-Related Cost Factors

(¢ per kWh)

Rate Class	Base & Prospective	EMF	EMF Interest	Total Fuel Factor
Residential	2.344	0.394	0	2.738
Small General Service	2.527	0.217	0	2.744
Medium General Service	2.468	0.236	0	2.704
Large General Service	2.056	0.666	0	2.722
Lighting	2.281	0.548	0	2.829

TABLE 2 – Public Staff PROPOSED Fuel and Fuel-Related Cost Factors (¢ per kWh)

Rate Class	Base & Prospective	EMF	EMF Interest	Total Fuel Factor
Residential	2.326	0.373	0	2.699
Small General Service	2.499	0.198	0	2.697
Medium General Service	2.456	0.218	0	2.674
Large General Service	2.054	0.648	0	2.702
Lighting	2.217	0.530	0	2.747

For comparison, Table 3 below provides the existing fuel and fuel-related cost factors (excluding the regulatory fee) approved in Docket No. E-7, Sub 1173:

TABLE 3 – EXISTING Fuel and Fuel-Related Cost Factors (¢ per kWh)

Rate Class	Base & Prospective	EMF	EMF Interest	Total Fuel Factor
Residential	2.311	0.575	0	2.886
Small General Service	2.556	0.363	0	2.919
Medium General Service	2.477	0.343	0	2.820
Large General Service	1.757	1.038	0	2.795
Lighting	2.251	0.885	0	3.136