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February 9, 2022

VIA ELECTRONIC FILING

Ms. A. Shonta Dunston
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's 2020 IRP Supplemental Portfolio B
Docket No. E-100, Sub 165

Dear Ms. Dunston:

Enclosed for filing in the above-referenced docket, please find Duke Energy Carolinas LLC's ("DEC") and Duke Energy Progress LLC's ("DEP" and together with DEC, the "Companies") 2020 IRP Supplemental Portfolio B – Limited Appalachain Gas Availability and Modified Gas Forecasting Assumptions ("Supplemental Portfolio B").

The Companies are filing Supplemental Portfolio B in response to the Commission's November 19, 2021 Order Accepting Integrated Resource Plans, REPS, and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning, which directed the Companies to file an additional iteration of their Base Portfolio with Carbon Policy with certain modified assumptions. Supplemental Portfolio B is being filed herewith in accordance with the Commission's directive.

If you have any questions, please do not hesitate to contact me. Thank you for your attention to this matter.

Sincerely,

Jack E. Jirak

Enclosure

cc: Parties of Record

Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's
2020 IRP Supplemental Portfolio B – Limited Appalachian Gas Availability and Modified Gas Forecasting Assumptions

Docket No. E-100, Sub 165
February 9, 2022

On November 19, 2021, the North Carolina Utilities Commission (the "Commission") issued its Order Accepting Integrated Resource Plans, REPS, and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning (the "2020 IRP Order" or the "Order). As part of the 2020 IRP Order, the Commission directed Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies") to "prepare and file one additional iteration of their Base Portfolio with Carbon Policy portfolios that assumes limited DS Hub Gas . . . and also relies on no more than eight years of forward natural gas prices before using fundamental forecast data for the remainder of the planning period."[1] In response to the Commission's Order, the Companies have each prepared supplemental portfolios, modifying the Portfolio B – Base Case with Carbon Policy ("Portfolio B") that was filed as part of their respective 2020 Integrated Resource Plans ("IRP"). The supplemental portfolios—entitled Supplemental Portfolio B – Limited App Gas ("Supplemental Portfolio B")—are presented in this filing in accordance with the Commission's directive.

I. Background

This modified Supplemental Portfolio B shows the impact to 2020 IRP Portfolio B assuming more stringent limits on the Companies' ability to obtain natural gas from the Appalachian region. Referred to in the order as "DS Hub Gas," Dominion South Point is a production hub of natural gas that typically trades at a discount relative to Transco Zone 5 natural gas. In their 2020 IRPs, the Companies assumed that the Companies would be able to procure gas from the Appalachian region in the future as a result of pipeline addition or expansion, or the release of existing transportation service to the Carolinas region. For new natural gas combined cycle units in the 2020 IRPs, the Companies assumed that, in addition to the installed capital and fixed costs of the new generation units, the Companies would incur an incremental forecasted interstate Firm Transportation ("FT") cost for this pipeline reservation. The FT allows the Companies to buy natural gas at Appalachian region hub commodity pricing and accounts for the transmission of that gas to the Companies' service territories. In their 2020 IRPs, the Companies did not assume a limit to access incremental interstate FT services, and therefore all future combined cycle ("CC") units were available to operate at this lower cost natural gas commodity pricing.

To prepare Supplemental Portfolio B, the Companies worked with the North Carolina Utilities Commission Public Staff ("Public Staff") to develop interstate FT availability and other fuel price forecasting assumptions to be included in the supplemental portfolio. Supplemental Portfolio B utilizes the same FT assumptions from the Companies' original 2020 IRPs, but limits the incremental volume of interstate FT available for new generation such that it can fuel only one new CC.

[1] 2020 IRP Order, at 10.

Additionally, as ordered by the Commission, Supplemental Portfolio B includes no more than eight years of forward natural gas pricing before using full fundamental natural gas pricing. Specifically, the Companies used five (5) years of natural gas market prices, transitioned to fundamentals over the following three (3) year period, and used full fundamentals-based natural gas pricing by the start of year nine (9). The Public Staff agreed to this approach as an appropriate implementation of the Commission's directive. The Public Staff also requested that the Companies update the fuel commodity (natural gas, coal, and oil) market-based prices (used on the front end of the fuel price curves) and the fundamentals-based price (used on the back end of the fuel price curves) consistent with the fuel prices used in the 2021 NC Avoided Cost Filling, E-100, Sub 175. The Companies agreed to this proposal and implemented it in Supplemental Portfolio B.

II. <u>Portfolio Analysis</u>

The Companies used data and inputs from the original 2020 IRP Portfolio B as the basis for the development of Supplemental Portfolio B. The only changes to this data include those described above, updating the market and fundamental fuel price curves, the natural gas transition from market-based to fundamentals-based pricing schedule, and the availability of future natural gas CC on Appalachian region priced gas.

Tables 1 and 2 present the expansion plan results from the Companies' original 2020 IRP Portfolio B as compared to Supplemental Portfolio B.

Table 1: Portfolio B Expansion Plan – MW Additions by Year

		Portfolio B															
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
DEP	CC								1,224	1,224							2,448
	CT						457	457		913							1,826
	Battery											481				539	1,019
	Solar/S+S										150	150	225	225	225	225	1,200
	Onshore Wind													150	150	150	450
DEC	CC															1,224	1,224
	CT										457	457				913	1,826
	Battery																0
	Solar/S+S					75	75	75	75	150	150	150	300	300	300	300	1,950
	Onshore Wind																0

Table 2: Supplemental Portfolio B – Limited Appalachian Gas Expansion Plan – MW Additions by Year

		Supplemental Portfolio B-Limited App Gas															
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
DEP	CC								1,224								1,224
	CT						457	457		1,826							2,740
	Battery									481					539		1,019
	Solar/S+S								75	75	150	150	225	225	225	225	1,350
	Onshore Wind									150	150	150	150	150	150	150	1,050
DEC	CC																0
	CT										457	457				2,283	3,196
	Battery																0
	Solar/S+S					75	75	75	150	225	225	225	300	300	300	300	2,250
	Onshore Wind												150				150

Supplemental Portfolio B reduces the total number of CCs from three (3) to one (1). This single available CC is selected in 2028 and located in DEP, consistent with Portfolio B, upon the retirement of coal capacity in DEP in that year. The remainder of the needed capacity to maintain planning reserve margins, both in DEP and DEC are met primarily through incremental simple cycle combustion turbines ("CTs"), peaking resources which are restricted to operations on Transco Zone 5 natural gas pricing and equipped with oil backup to ensure firm capacity of the unit. Supplemental Portfolio B inherently relies more on less efficient CTs and existing coal generation to make up the loss of the incremental CCs in 2029 in DEP and in 2035 in DEC from original Portfolio B. The total new natural gas capacity is generally consistent between the two portfolios, only varying due to the different sizes of the resources.

III. <u>Present Value of Revenue Requirement</u>

Tables 3 and 4 provide comparisons of the present value of revenue requirements (PVRR) for Portfolio B and Supplemental Portfolio B. The PVRR is shown for DEC, DEP, and the combined Carolinas system. The tables present the delta between the Supplemental Portfolio B and the original 2020 IRPs' Portfolio B to show the impact of the updated assumptions and associated impact on the Companies' expansion plans and portfolio cost performance.

Table 3: Projected PVRR through 2050 (Excluding the Explicit Cost of Carbon) [$ Billions]

	PVRR Through 2050 (Excluding the Explicit Cost of Carbon)		
	DEC	DEP	Carolinas Combined
Portfolio B	46.8	35.7	82.5
Supplemental Portfolio B-Limited Appalachian Gas Expansion Plan	50.3	37.5	87.7
Delta Supplemental Portfolio B to Portfolio B	*3.5*	*1.8*	*5.2*

Table 4: Projected PVRR through 2050 (Including the Explicit Cost of Carbon) [$ Billions]

	PVRR Through 2050 (Including the Explicit Cost of Carbon)		
	DEC	DEP	Carolinas Combined
Portfolio B	55.1	43.7	98.8
Supplemental Portfolio B-Limited App Gas	59.3	45.4	104.7
Delta Supplemental Portfolio B to Portfolio B	*4.3*	*1.7*	*6.0*

The PVRRs calculated above are consistent with how the system costs were developed for the original 2020 IRPs. The difference between Tables 3 and 4 represents the difference in exclusion or inclusion of the explicit cost of carbon emissions assumed in the development and performance of these portfolio, represented by the Companies' 2020 IRP Base Carbon Policy proxy price as described in the Companies' 2020 IRPs.

As shown in Tables 3 and 4, the limitation of additional combined cycles and adjustments to the underlying commodities prices updated from the 2020 IRPs' base planning assumptions to the 2021 Sub 175 Avoided Cost commodity prices in the Supplemental Portfolio B results in a more costly system. The incremental combined cycles in Portfolio B provide considerable production cost value to the system, offsetting more costly generation, especially associated with coal generation.

IV. <u>Summary and Conclusion</u>

Limiting the system to just one (1) new CC with access to Appalachian region priced natural gas results in switching resources from efficient natural gas CCs with low dispatch cost to relying more on less efficient peaking resources and remaining coal generation to fill the energy needs of the system. It is important to note that while this sensitivity imposes more conservative

FT natural gas pricing availability assumptions than assumed in the 2020 IRP, the Companies maintain there are options to secure future firm transportation service for future natural gas generation from the Appalachian region.