STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 190

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)	))))))	**DIRECT TESTIMONY OF CLIFT POMPEE, STEVEN CAPPS, AND BEN SMITH ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION AND OVERVIEW

Q. MR. POMPEE, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Clift Pompee, and my business address is 525 South Tryon Street, Charlotte, North Carolina, 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Carolinas, LLC ("DEC") as the Managing Director of Generation Technology.

Q. BEFORE INTRODUCING YOURSELF FURTHER, WOULD YOU PLEASE INTRODUCE THE PANEL.

A. Yes. I am appearing on behalf of DEC and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies" or "Duke Energy") together with Steven Capps and Ben Smith on the "Long Lead Generation and Pumped Storage Hydro Panel (BCII, New Nuclear, OSW)." Witnesses Capps and Smith will introduce themselves.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I am responsible for providing leadership and direction for the review and awareness of new generation technologies, their domestic and global applications and functionality/performance and potential application for Duke Energy. I also support the development of generation portfolios of technologies that ensure affordability for our customers, resource adequacy, energy sufficiency, and system reliability to achieve Duke Energy's carbon reduction goals.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated with Honors from the University of Miami in 2001 with a Bachelor of Science degree in Mechanical Engineering with an Aerospace area of focus. I started my career in August 2001 as an associate engineer providing steam turbine engineering support with Florida Power & Light Company ("FPL"). I held multiple roles with FPL including plant engineering, operations, maintenance, monitoring & diagnostics and quality assurance. In 2008, I started working for Progress Energy as a nuclear assessor providing oversight of Nuclear Major Projects. In 2011, worked as the supervisor of project controls scheduling and transitioned into that role in 2012, when Progress Energy and Duke Energy merged. I led the merger integration of the Nuclear Major Projects scheduling processes between the two legacy companies. In 2014, I joined the Fossil-Hydro ("FHO") organization as a gas turbine program manager, overseeing the GE 7F gas turbine program. In 2015, I became the manager of the Information and Analytics Group and worked on integrating analytics and data science into our FHO operations. This role evolved into becoming a product manager for digital transformation in 2018, where I used my background in operations, maintenance and engineering to oversee multiple digital products that the company was developing. In June 2021, I transitioned into my current role and have been responsible for evaluating emerging generation technologies that could support our decarbonization goals.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION")?

A. Yes. I previously testified before the Commission in Docket No. E-100, Sub 179.

Q. MR. CAPPS, PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Steven D. Capps, and my business address is 13225 Hagers Ferry Road, Huntersville, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy as Senior Vice President of Nuclear Operations.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. As Senior Vice President of Nuclear Operations, I am responsible for providing executive oversight for the safe and reliable operation of Duke Energy's three South Carolina operating nuclear stations. I am also involved in the operations of Duke Energy's other nuclear stations located in North Carolina. Since the formation of the New Nuclear Generation group in June of 2022, I've had executive oversight of the work Duke Energy is performing with advanced nuclear.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a Bachelor of Science degree in Mechanical Engineering from Clemson University and have over 36 years of experience in the nuclear field in various roles with increasing responsibilities. I joined Duke Energy in 1987 as a field engineer at the Oconee Nuclear Station ("Oconee"). During my time at Oconee, I served in a variety of leadership positions at the station, including Senior Reactor Operator, Shift Technical Advisor, and Mechanical and Civil Engineering Manager. In 2008, I transitioned to the McGuire Nuclear Station ("McGuire") as the Engineering Manager. I later became plant manager and was named Vice President of McGuire in 2012. In December 2017, I was named Senior Vice President of Nuclear Corporate for Duke Energy with direct executive accountability for the Companies' nuclear corporate functions, including nuclear corporate engineering, nuclear major projects, corporate governance and operation support and organizational effectiveness. I assumed my current role in October 2018.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes. I provided testimony and appeared before the Commission in DEC's 2019 base rate case in Docket No. E-7, Sub 1214 and DEC's fuel and fuel related cost recovery proceeding in Docket No. E-7, Sub 1163. I provided testimony in

DEC's fuel and fuel-related cost recovery proceedings in Docket Nos. E-7, Sub 1190, E-7, Sub 1228, E-7, Sub 1250, E-7, Sub 1263, and E-7, Sub 1282.

Q. MR. SMITH, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Benjamin Smith, and my business address is 525 South Tryon Street, Charlotte, North Carolina, 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by DEC as Generation & Regulatory Strategy Director.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. As Generation & Regulatory Strategy Director, I am responsible for assisting with the generation fleet transition strategy. This includes developing strategic decisions, preparing business cases, and working new generation projects including but not limited to Bad Creek II and coal retirements.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from the University of Kentucky with a bachelor's degree in Finance. I also graduated from Thomas More College with a master's degree in Business Administration. My career began with Cinergy (DBA Duke Energy) in 1999 as a Financial Analyst in the Regulated Business department. In 2007, I moved to the Non-Regulated Operations Group as Storeman Supervisor at Zimmer Station. Then, in 2009, I was named the Business Manager of Zimmer Station, supporting the financial functions of the station. In 2011, I was named

Manager of Finance supporting Duke Energy's Fossil Hydro Fleet. Following the merger of Duke Energy and Progress Energy, I was named Manager of Performance Metrics supporting Supply Chain. I have been in my current department since 2015, first as Generation & Regulatory Strategy Manager and promoted to Generation & Regulatory Strategy Director in 2018. In my current position, I have been responsible for the development of the Bad Creek II expansion for approximately five years, including the feasibility studies and strategy to ensure it is a viable option for the energy transition.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. No.

Q. IS THE PANEL SPONSORING ANY EXHIBITS?

A. Yes. Witness Pompee supports Long-Lead Time and Pumped Storage Hydro Panel Exhibit 1.

Q. MR. SMITH, ON BEHALF OF THE PANEL, WHAT IS THE PURPOSE OF THE PANEL'S TESTIMONY?

A. The Panel's testimony sponsors and highlights several key themes and issues relating to (1) the Companies' planning and execution of pumped storage hydro ("PSH"), (2) the expansion of Duke Energy's existing nuclear generation fleet, (3) the development of advanced nuclear generation technologies, and (4) the development of offshore wind resources (collectively, the "Long Lead-Time Resources" or "LLTR"), as further addressed in Chapter 4 (Execution Plan),

Appendix I (Renewables and Energy Storage) and Appendix J (Nuclear) of the 2023-2024 Carbon Plan and Integrated Resource Plan ("CPIRP" or "the Plan"), filed with the Commission on August 17, 2023. This Panel's testimony provides an overview of the Companies' ongoing efforts to evaluate and integrate LLTR into the Companies' generation and resource mix pursuant to the Commission's directives in its December 30, 2022 Order Adopting Initial Carbon Plan and Providing Direction for Future Planning issued in Docket No. E-100, Sub 179 ("Carbon Plan Order").[1] The Panel's testimony supports these ongoing activities as well as the Companies' execution planning to continue to evaluate offshore wind resources, optimize existing nuclear facilities, and develop PSH facilities and new nuclear facilities in the near-term between now and 2026.

Q. PLEASE EXPLAIN HOW THIS PANEL'S TESTIMONY IS ORGANIZED.

A. Section II of the Panel's testimony identifies the portions of the Plan and the Companies' related Requests for Relief that this Panel sponsors.

Section III of the Panel's testimony addresses how the Companies are meeting specific directives established by the Carbon Plan Order and provides support for the Requests for Relief presented in their CPIRP.

II. SPONSORSHIP OF THE PLAN

Q. MR. SMITH, PLEASE IDENTIFY WHICH SECTIONS OF THE PLAN YOU ARE SPONSORING BY THIS DIRECT TESTIMONY.

[1] Order Adopting Initial Carbon Plan and Providing Direction for Future Planning, Docket No. E-100, Sub 179 (Dec. 30, 2022) ("Carbon Plan Order").

A. I am sponsoring the Plan sections addressing the Companies' activities related to PSH facilities, specifically Bad Creek II ("BCII"):

- Chapter 4, Execution Plan (Bad Creek II). This section presents the Companies' Near-Term Action Plan ("NTAP") for executing the 2023 Resource Plan, and I am specifically sponsoring development activities for BCII resources as identified in Table 4-8.
- Appendix I, Renewables and Energy Storage. This Appendix describes the current and future planning considerations for BCII in the Carolinas, including how additional PSH helps meet the Companies' generation and storage needs and complements the increasing levels of solar and planned wind generation on the system. This Appendix also describes the risks and risk management associated with PSH.
- Chapter 2, Methodology and Key Assumptions. I also contributed to the modeling assumptions for PSH.

Q. MR. CAPPS, PLEASE IDENTIFY WHICH SECTIONS OF THE PLAN YOU ARE SPONSORING WITH THIS DIRECT TESTIMONY.

A. I am sponsoring the parts of the Plan describing the Companies' actions to optimize their existing nuclear generation fleet and develop new nuclear technologies, as follows:

- Chapter 4, Execution Plan (Nuclear). This section presents the Companies' NTAP for executing the 2023 Resource Plan, and I am specifically sponsoring development activities for extending the life of the existing nuclear fleet as identified in Table 4-5, and for our advanced nuclear strategy as identified in Table 4-12.

- Appendix J, Nuclear. This Appendix provides information on the Companies' efforts to comply with the carbon emission reduction requirements established by HB 951 through the power output expansion of Duke Energy's existing nuclear generation fleet, progressing with subsequent license renewal ("SLR") of the existing fleet, and the development of new advanced nuclear generation technologies, which will provide reliable, carbon-free, baseload energy to the Companies' customers.
- Chapter 2, Methodology and Key Assumptions. I provided input for the modeling assumptions for existing nuclear power output expansions and for new advanced nuclear.

Q. MR. POMPEE, PLEASE IDENTIFY WHICH SECTIONS OF THE CPIRP YOU ARE SPONSORING WITH THIS DIRECT TESTIMONY.

A. I am sponsoring the Plan sections addressing the Companies' near-term actions related to offshore wind resources:

- Chapter 4, Execution Plan (Offshore Wind). This section presents the Companies' NTAP for evaluating offshore wind resources in the 2023 Resource Plan, and I am specifically sponsoring near-term actions for offshore wind resources as identified in Table 4-11.

- Appendix I, Renewables and Energy Storage. This Appendix describes the current and future planning considerations for offshore wind in the Carolinas, including the potential for offshore wind to help meet the Companies' long-term generation needs and how it complements the increasing levels of solar on the system. This Appendix also describes the risks and risk management associated with offshore wind.
- Chapter 2, Methodology and Key Assumptions. I also provided input data used by the modeling team to create the generic assumptions for offshore wind.

Q. PLEASE IDENTIFY THE REQUESTS FOR RELIEF PRESENTED IN THE COMPANIES' CPIRP PETITION AND BOWMAN EXHIBIT 1 THAT THE PANEL IS SUPPORTING THROUGH ITS TESTIMONY.

A. The Panel supports CPIRP Requests for Relief 2(a)(vi), 2(b), and 2(c)(i) as being in the public interest and requests Commission approval of the development of these generation resources as necessary and reasonable steps to execute the CPIRP during the near-term. The Panel also supports Request for Relief 2(c)(iii), requesting authorization to incur project development costs up to $165 million for the development of pumped storage hydro from 2023 through 2026 for purposes of achieving approximately 1700 megawatts ("MW") in service by 2033. Additionally, the Panel supports Request for Relief 2(c)(iv), requesting authorization to incur additional project development costs up to $365 million through 2026 for the development of advanced nuclear resources. The Panel also supports Requests for Relief 3, approval of the Companies' proposed actions with respect to existing supply-side resources, including the continued disciplined pursuit of SLRs and authorization to incur project development costs up to $389.6 million for specific power output expansion projects, which includes power uprate projects, measurement uncertainty recapture projects, and 24-month fuel cycle extensions for the Companies' existing nuclear fleet, as described in Appendix J.

III. <u>PROGRESS ADDRESSING CARBON PLAN ORDER DIRECTIVES</u>

A. <u>PSH Facilities – Bad Creek II</u>[2]

Q. MR. SMITH, HOW IS DUKE ENERGY INCORPORATING PSH TECHNOLOGY INTO ITS EFFORTS TO COMPLY WITH THE REQUIREMENTS OF SESSION LAW 2021-165 ("HB 951")?

A. As discussed in Chapter 4 and Appendix I, Bad Creek II is a key resource to assist with meeting the requirements of HB 951 and the energy transition. The projected in-service date for Bad Creek II aligns with the coal retirement schedule and provides capacity to replace a portion of the retired MW. Bad Creek II provides diversification of storage with standalone storage and solar plus storage. PSH complements the significant amount of solar that is expected on the grid in the near future by storing excess renewable energy during times of low demand and providing energy when demand is high.

[2] Carbon Plan Order at 133 (Ordering Paragraph No. 25).

Q. DID ANY PARTY TO THE 2022 CARBON PLAN PROCEEDING IN DOCKET NO. E-100, SUB 179 ("2022 CARBON PLAN PROCEEDING") OPPOSE THE COMPANIES' PLANS TO PURSUE DEVELOPMENT AND CONSTRUCTION OF BCII?

A. No. No party opposed the Companies' plan to pursue development and construction of Bad Creek II. In the Carbon Plan Order, the Commission approved the request to move forward with certain limited development activities for BCII and approved the Companies' request to incur costs associated with those development activities up to $40 million subject to the Commission's authority to review specific costs in a future general rate case.

Q. MR. SMITH, WILL YOU PLEASE PROVIDE AN UPDATE ON THE DEVELOPMENT ACTIVITIES AND COSTS THAT THE CARBON PLAN ORDER APPROVED?

A. Yes. DEC has incurred approximately $7 million in costs related to the development of Bad Creek II. The development activities for which costs have been incurred include the completion of a pre-feasibility study and a feasibility study, performed by a third-party engineering firm, as well as ongoing geotechnical exploration work. DEC also issued a Request for Proposals ("RFP") in May 2023 for the centerline—which includes pump turbines, generators and excitation power electronics, and major equipment—and anticipates receiving bids in September 2023. The RFP is the first step in the process to ensure original equipment manufacturer ("OEM") modeling and engineering can be completed and equipment can be ordered prior to the start of construction. Additionally, Bad Creek II entered the 2022 Definitive Interconnection System Impact Study ("DISIS"), a generator interconnection cluster study established by the North Carolina Interconnection Procedures, in June 2022 to determine the system impacts of the project.

Q. HOW DO THE CURRENT PROJECTED DEVELOPMENT COSTS THROUGH 2024 FOR BCII COMPARE TO THE NEAR-TERM DEVELOPMENT COSTS THAT WERE AUTHORIZED BY THE CARBON PLAN ORDER?

A. The Carbon Plan Order authorized the Companies to incur up to $40 million of development costs for Bad Creek II through 2024. DEC currently projects that it will spend approximately $30.4 million of that $40 million through 2024. Table 1 below provides the costs through June 2023 and total projected spend through 2024.

Table 1: Bad Creek II Activity Description and Spend (2022-2024

Activity Description	CP 2022 - 2024 Projected Spend Total ($M)	Actual Spend Thru June 2023 ($M)	Projected Spend Thru 2024 ($M)	Total ($M)
Pre-Feasibility/Feasibility Study	5.0	2.9	0.0	2.9
Support Project Optimization and Functional Design (Support EPC Ten	7.0	1.1	0.8	2.0
Execute Phase 2 Geotech Exploration	1.5	1.5	0.5	2.0
Phase 2 Geotech Exploration Field Support and Analysis	1.5	0.1	0.9	1.0
Major PH Equipment Solicitation Support Activities				
Support Bid Spec Prep	1.0	0.2	0.0	0.2
Support OEM Bid Evaluation and Contract Negotiation	0.5	0.0	0.6	0.6
OEM Hydraulic Design and Model Testing	3.0	0.0	8.0	8.0
EPC Solicitation Support Activities				
HDR Support Contract Strategy and Planning	0.4	0.0	0.4	0.4
HDR Prepares Tech Specs / Exhibits in Support of Duke's EPC Solicit	3.0	0.0	3.0	3.0
Large Generator Interconnect Study	0.3	0.5	0.5	1.0
EPC Independent Estimate Review	0.5	0.0	1.4	1.4
Project Mgmt, Project Engineering, Implementation Mgmt	0.8	0.8	1.6	2.4
Contingency	4.0	0.0	4.0	4.0
Licensing	7.5	0.0	1.5	1.5
Total	**35.9**	**7.1**	**23.3**	**30.4**

Q. WHAT ARE THE COMPANIES' PROJECTED NEAR-TERM DEVELOPMENT COSTS FOR BAD CREEK II IN THEIR CPIRP?

A. The Companies' CPIRP includes projected near-term costs for Bad Creek II of approximately $165 million, which includes projected costs through 2026. These costs are outlined in Chapter 4 of the CPIRP and are included in more detail in Table 2 below.

<u>Table 2: Bad Creek II Activity Description and Spend (2023-2026)</u>

Activity Description	2023	2024	2025	2026	Total
Pre-Feasibility/Feasibility Study	12,273	0	0	0	12,273
Support Project Optimization and Functional Design (Support EPC Tender)	1,601,172	965,000	0	0	2,566,172
Execute Phase 2 Geotech Exploration	1,155,209	490,364	0	0	1,645,573
Phase 2 Geotech Exploration Field Support and Analysis	175,878	100,000	0	0	275,878
Major PH Equipment Solicitation Support Activities					
Support Bid Spec Prep	71,898	0	0	0	71,898
Support OEM Bid Evaluation and Contract Negotiation	185,180	187,000	0	0	372,180
OEM Hydraulic Design and Model Testing (Phase 1 Award)	0	8,000,000	2,000,000	0	10,000,000
OEM Detail Design of Major Equipment (Phase 2 Award)	0	0	18,000,000	25,000,000	43,000,000
EPC Solicitation Support Activities					
HDR Support Contract Strategy and Planning	0	400,000	400,000	0	800,000
HDR Prepares Tech Specs / Exhibits in Support of Duke's EPC Solicitation	0	3,000,000	1,500,000	0	4,500,000
Large Generator Interconnect Study	150,000	350,000	0	0	500,000
EPC Independent Estimate Review	1,400,000	0	0	0	1,400,000
Project Mgmt, Project Engineering, Implementation Mgmt	987,835	1,060,319	1,600,000	1,600,000	5,248,154
Licensing (FERC)	600,000	900,000	2,000,000	1,000,000	4,500,000
Consultant Services (Project Schedule Analysis, Commercial Strategy Development)	0	1,000,000	1,000,000	1,000,000	3,000,000
Temporary Road Construction (Fishers Knob Residential Access)	0	0	5,000,000	5,500,000	10,500,000
EPC LNTP	0	0	7,500,000	22,500,000	30,000,000
Studies/Permitting	0	250,000	500,000	500,000	1,250,000
Contingency	4,000,000	4,000,000	19,000,000	19,000,000	46,000,000
Total	**10,339,445**	**20,702,683**	**58,500,000**	**76,100,000**	**165,642,128**

Q. IS DUKE ENERGY REQUESTING THAT THE COMMISSION MAKE ANY DETERMINATIONS REGARDING THE 2023-2026 PROJECTED COSTS IDENTIFIED IN TABLE 2?

A. Yes. As stated in Request for Relief 2(C)(iii), DEC is requesting Commission approval to incur the project development costs up to $165 million for the development of PSH from 2023 through 2026. In addition, while DEC is not seeking to recover specific costs for Bad Creek II in this proceeding, DEC wants to take the opportunity to acknowledge that recovery of the Companies' financing costs for Bad Creek II during the construction period will be an important consideration in the Company's ability to successfully execute the project. Given the impact of an investment of this size, particularly in the broader context of the ongoing energy transition, timely recovery of financing costs protects the financial stability of the utility and helps to ensure strong credit ratings to facilitate the lowest possible financing costs for customers. As a result, DEC plans to request in a future proceeding that the Commission approve inclusion of construction work in progress in rate base for Bad Creek II.

B. <u>Nuclear</u>

Q. MR. CAPPS, WHAT ROLE DOES EXISTING AND NEW NUCLEAR GENERATION PLAY IN THE COMPANIES' PLAN?

A. Existing and new nuclear generation will play a vital role in meeting customers' needs while transitioning to a cleaner energy future and achieving the targeted emission reductions under HB 951. With respect to existing nuclear generation, the Companies are pursuing subsequent license renewals ("SLR") for their existing nuclear generation fleet; identifying opportunities to expand output for their existing nuclear units through power uprate ("PUR"), measurement uncertainty recapture ("MUR"), and 24-month refuel cycle projects. With respect to new nuclear generation, the Companies are moving forward with development activities that will allow Duke Energy to incorporate advanced nuclear technologies such as small modular reactors ("SMRs") and advanced reactors ("ARs") into the Companies' generation resource mix.

Q. DID ANY PARTY TO THE 2022 CARBON PLAN PROCEEDING OPPOSE THE COMPANIES' PLANS TO PURSUE SLRS FOR THEIR EXISTING NUCLEAR FLEET?

A. No. No party to the 2022 Carbon Plan proceeding opposed Duke Energy's plans to pursue SLRs for its existing fleet and no party provided a substantive discussion around the specifics of the SLR proposal. The Public Staff recognized that Duke Energy's existing nuclear fleet serves as a foundational component for compliance with the CO_2 emissions reduction mandates of HB 951, and other parties acknowledged the significant amount of carbon-free, low-cost baseload generation capacity that would be lost if the Companies did not extend the operating licenses for their nuclear fleet.[3]

Q. DID THE COMMISSION APPROVE THE COMPANIES' PLANS TO PURSUE SLRS FOR ITS NUCLEAR FLEET?

A. Yes. In its Carbon Plan Order, the Commission found that Duke Energy's existing nuclear generation fleet provides a significant portion of carbon-free electric generation capacity for customers in North Carolina and South Carolina and noted that no party had contested the Companies' pursuit of SLR for the

[3] Carbon Plan Order at 66.

nuclear fleet.[4] As a result, the Commission concluded that it was reasonable and appropriate for Duke Energy to pursue SLRs for its existing nuclear fleet.[5] In compliance with the Commission's directive, Duke Energy has continued to pursue SLR for its nuclear generation facilities.[6]

Q. DID THE COMMISSION ORDER DUKE ENERGY TO PROVIDE ANY INFORMATION REGARDING ITS PURSUIT OF SLRS IN FUTURE CPIRP FILINGS?

A. Yes. In the Carbon Plan Order, the Commission directed the Companies to develop a schedule detailing its plans for SLR of the existing nuclear fleet and to provide that information in the Companies' upcoming CPIRP filing. The Commission also directed the Companies to review the SLR applications that the Nuclear Regulatory Commission ("NRC") reversed in early 2022, and to incorporate any lessons learned in the preparation of Duke Energy's application for its existing nuclear fleet.[7]

Q. HAVE THE COMPANIES COMPLIED WITH THE COMMISSION'S DIRECTIVE TO DEVELOP A SCHEDULE DETAILING DUKE ENERGY'S PLANS FOR SLR OF THE EXISTING NUCLEAR FLEET?

A. Yes. Figure J-3: Duke Energy Nuclear Fleet SLR Timeline, which is contained in Appendix J to the Plan, provides a timeline of the SLR applications for the Companies' existing nuclear fleet. As noted in Appendix J, the SLR process is

[4] Carbon Plan Order at 67.

[5] *Id.*

[6] Carbon Plan Order at 132 (Ordering Paragraph No. 12).

[7] Carbon Plan Order at 132 (Ordering Paragraph No. 13).

complex and time-consuming, and each application takes approximately three years to prepare and approximately two years to be reviewed by the NRC. Each SLR application will be submitted to the NRC within the timeline needed prior to the current license expirations to ensure continued operation.

Q. HOW WILL THE COMPANIES KEEP THE COMMISSION APPRISED OF THEIR PLANS TO PURSUE SLRS FOR THEIR NUCLEAR GENERATION FACILITIES?

A. Duke Energy will continue to include a discussion and timeline describing its pursuit of SLRs in future CPIRP filings. As shown in Figure J-3, the SLR application submission and review process is projected to last until 2037, with the Harris Nuclear Plant being the last facility that will apply for an SLR. The Companies will continue to update the information being provided in Appendix J to reflect the status of all SLR applications for their existing nuclear fleet in future CPIRP filings.

Q. HAVE THE COMPANIES COMPLIED WITH THE COMMISSION'S DIRECTIVE TO INCORPORATE SLR LESSONS LEARNED FROM THE TWO NUCLEAR LICENSES THAT THE NRC REVERSED IN EARLY 2022 INTO THE COMPANIES' CPIRP FILING?

A. Yes. As discussed in Appendix J, the NRC's conclusion that a renewal Generic Environmental Impact Statement ("GEIS") does not apply for an SLR resulted in the NRC reversing its approvals of the SLR applications submitted by Florida

Power & Light Company for its Turkey Point Units 3 and 4 and impacts all SLR applicants going forward. The NRC is currently conducting a rulemaking proceeding to revise the GEIS for use in SLR applications. Duke Energy has reviewed the NRC's decisions and has incorporated lessons learned from the ruling. The Companies will use the revised GEIS for all future SLR submittals when the rule is approved and issued by the NRC. The previously submitted SLR application for Oconee Nuclear Station was supplemented with site-specific information resolving the issue for that site.

Q. WHAT ARE THE BENEFITS OF DUKE ENERGY'S PLAN TO EXPAND THE OUTPUT OF ITS EXISTING GENERATION FLEET THROUGH POWER UPRATE ("PUR") AND MEASUREMENT UNCERTAINTY RECAPTURE ("MUR") PROJECTS AS WELL AS THE COMPANIES' PLAN TO SWITCH TO 24-MONTH FUELING CYCLES?

A. Table J-2, Power Output Expansion Projects at Existing Nuclear Plants, in Appendix J provides the detail of the PUR and MUR projects. Increasing the output capacity of the existing nuclear units identified in Table J-2 will add approximately 250 MW of new capacity through a more cost-effective and efficient use of the existing plants. The PUR and MUR projects are all scheduled to be implemented by year end 2031, providing clean carbon-free baseload generation prior to the addition of new advanced nuclear in 2034. The Companies' plan to switch to 24-month fueling cycles will result in longer durations of power output between fueling outages.

Q. WHAT ARE THE TOTAL PROJECTED COSTS ASSOCIATED WITH POWER OUTPUT EXPANSION PROJECTS FOR THE EXISTING FLEET THAT ARE PLANNED IN THE NEAR-TERM AND INTERMEDIATE TERM?

A. The estimated costs related to the power output expansion projects for the existing fleet are provided in Appendix J, Table J-2, and are provided below in Table 3.

Table 3: Power Output Expansion Projects at Existing Nuclear Plants[8]

Units	Expansion Type	Estimated Additional MW Total	Estimated In-Service Date	Estimated Cost ($Million) 2023-2026	Estimated Cost ($Million) 2027-2031	Total Estimated Cost ($Million)
Brunswick Unit 1 & Unit 2	MUR	26	Q1 2028 (B U2) Q1 2029 (B U1)	$7.1	$5.0	$12.1
Catawba Unit 1, McGuire Unit 1 & Unit 2	PUR	225	Q4 2029 (M U1) Q4 2030 (M U2) Q2 2031 (C U1)	$313.1	$1,010.5	$1,323.6
Catawba Unit 1 & Unit 2, Harris Unit 1, and McGuire Unit 1 & Unit 2	24MFC	TBD	Q2 2029 (C U1) Q3 2029 (M U1) Q2 2030 (C U2) Q4 2030 (M U2) Q4 2031 (H U1)	$69.4	$49.2	$118.6
Totals		251		$389.6	$1,064.7	$1,454.3

Q. WHAT WERE THE COMMISSION'S FINDINGS IN THE CARBON PLAN ORDER REGARDING DUKE ENERGY'S PROPOSAL TO INCUR PROJECT DEVELOPMENT COSTS TO PURSUE ADVANCED NUCLEAR TECHNOLOGIES?

[8] CPIRP Appendix J at 8 (Table J-2).

A. The Commission found that Duke Energy had demonstrated, by a preponderance of the evidence, that the decision to incur certain project development costs to pursue new nuclear technologies was reasonable and prudent, capped such project development costs incurred between through 2024 at $75 million, and ordered the Companies to report on their activities and costs incurred in pursuing the authorized development work in their next CPIRP filing.[9]

Q. HAVE THE COMPANIES COMPLIED WITH THESE DIRECTIVES?

A. Yes. As shown in Table J-9 of Appendix J, Advanced Nuclear Costs Incurred to Date, Duke Energy projects costs through the end of 2024 of less than the $75 million cap established by the Commission's Carbon Plan Order. Appendix J further provides a report in Table J-8, Major Development Activities Status, on the status of Duke Energy's development activities to pursue advanced nuclear technologies, which include (1) forming a New Nuclear Generation organization within Duke Energy; (2) evaluating potential sites for an SMR or AR; (3) continuing to assess SMR and AR designs to determine which technology to pursue, leading to eventual technology selection; and (4) beginning work on a technology-neutral early site permit ("ESP"), which will eventually be used to site and begin construction of an advanced nuclear unit. Finally, Table J-10 provides estimated future costs in 2025-2026 of development activities required to pursue advanced nuclear.

[9] Carbon Plan Order at 96.

Q. WHAT ARE THE TOTAL PROJECTED COSTS ASSOCIATED WITH ADVANCED NUCLEAR THAT ARE PLANNED IN THE NEAR-TERM?

A. The estimated costs related to advanced nuclear are provided in Appendix J, Table J-10, and are provided below in Table 4.

Table 4: Estimated Future Costs for Advanced Nuclear (2025-2026)[10]

Site/Unit	Activities	Estimated Cost ($Million) 2025-2026
Belews Creek	• Early site permit	$35
Site 1* Units 1, 2, and 3	• Reactor technology vendor initial fee/long lead equipment • Construction permit/license application develop/approve • Construction	$220 $48 0
Site 2*	• Early site permit	$44
Site 2* Units 1, 2, and 3	• Reactor technology vendor initial fee/long lead equipment • Construction permit/license application develop/approve • Construction	0 $18 0
Totals		$365

C. Offshore Wind

Q. MR. POMPEE, HOW IS DUKE ENERGY INCORPORATING OFFSHORE WIND RESOURCES INTO ITS EFFORTS TO COMPLY WITH THE REQUIREMENTS OF HB 951?

A. The offshore wind market is a new and developing industry in the United States with very few operational wind turbines. As further addressed in Appendix I, the Companies do not currently own offshore wind development assets, including a wind energy area ("WEA") lease, and as directed by the NCUC,

[10] CPIRP Appendix J at 19 (Table J-10).

have been evaluating potential resource availability in the Carolinas, timeline for achieving commercial operation, as well as the costs and risks of deploying offshore wind. As identified in the NTAP and addressed in the Executive Summary and Chapter NC, offshore wind was not selected in the Companies' recommended Core Portfolio P3 Base through the end of the Base Planning Period by 2038 (though offshore wind is selected for long-term carbon neutrality). Therefore, the Companies' near-term actions do not include obtaining a lease and proceeding with more significant initial development activities required to make offshore wind available in the Carolinas in the early 2030s. However, the Companies will continue to evaluate the role of offshore wind in providing increasingly clean, diverse power to customers in the Carolinas and, if market conditions change or further regulatory direction is provided, the Companies could pursue further development activities.

Q. MR. POMPEE, THE CARBON PLAN ORDER REQUIRED THE COMPANIES TO PERFORM AN EVALUATION OF THE THREE CURRENTLY AVAILABLE WEAS OFF THE COAST OF NORTH CAROLINA.[11] CAN YOU PLEASE PROVIDE AN UPDATE ON THE EVALUATION?

A. The Companies engaged with the three North Carolina offshore wind parcel lessees (collectively, referred to as the "Developers") and retained DNV Energy USA Inc. ("DNV") as an industry expert to execute a non-binding request for

[11] Carbon Plan Order at 102-03 (Ordering Paragraph No. 26).

information ("RFI") process. Through this process, the Companies obtained information regarding in-service dates, capital and development costs, operating costs, transmission costs, generation profile and net capacity factor ("NCF") data ("Verified Inputs") from the Developers and used the Verified Inputs to calculate levelized cost of energy ("LCOE") for various project scenarios across the three lease areas ("WEA Evaluation"). The details and results of the WEA Evaluation are being submitted confidentially as Exhibit 1.

Q. THE COMMISSION ALSO REQUIRED THE COMPANIES TO EVALUATE THE WEAS AND INCLUDE BEST ESTIMATES OF ALL RELEVANT COSTS TO ACQUIRE AND DEVELOP A WEA AND COMPARE THE WEAS ON A SIMILAR BASIS TO ONE ANOTHER.[12] CAN YOU DESCRIBE HOW THE COMPANIES COMPLIED WITH THIS REQUIREMENT?

A. To comply with the Commission's directive to include best estimates of all relevant costs to acquire and develop a WEA evaluation and compare the WEAs on a similar basis to one another, the Companies required that all data provided by the Developers be verified and anonymized by DNV prior to being submitted to the Companies. Several working sessions were held between DNV and the IRP modeling team to ensure the anonymized Verified Inputs provided were interpreted correctly and modelled appropriately. Additionally, the Companies

[12] Carbon Plan Order at 102.

established the landing site, point of interconnection and project sizes to ensure the Developer submittals would be as comparable as reasonably possible.

Q THE COMMISSION FURTHER REQUIRED THE COMPANIES TO EVALUATE THE WEAS AND INCLUDE A COMPARISON OF THE LEVELIZED COST OF ENERGY TO THE POINT OF INJECTION ON DUKE ENERGY'S GRID.[13] CAN YOU DESCRIBE HOW THE COMPANIES COMPLIED WITH THIS REQUIREMENT?

A. As part of the WEA Evaluation and modeling process and in accordance with the Carbon Plan Order*,* the Companies derived LCOE estimates for each of the project scenario submissions. The Companies found that, in general, the larger capacity projects are estimated to have lower LCOE. This result was expected as significant efficiencies of scale can be realized in offshore wind developments. For example, in general, as turbine units are added to a project, the energy production per unit remains the same, while the CapEx, DevEx, and OpEx cost per unit decreases. However, there is a point of diminishing returns when a given project size necessitates more export cable runs, higher transmission costs, more network upgrades and additional offshore substation(s). This point of diminishing returns is unique to each proposed project given its location, depth, wind resource, conceptual design and other factors. NCF also has a significant impact on LCOE. Given the RFI process called for all projects to propose turbine models commercially available today

[13] Carbon Plan Order at 102.

up to approximately 15 MW, the difference in NCF estimates were primarily driven by the wind resource predicted at each location.

Q. DO THE COMPANIES CONSIDER THE LCOE RESULTS FOR THE PROJECT SCENARIOS AND ASSOCIATED WEAS IN EXHIBIT 1 TO BE DEFINITIVE?

A. No, the LCOE results in Exhibit 1 are not considered definitive as to which project would ultimately result in the lowest LCOE. In order to determine that, an RFP would have to be conducted at a future date, with binding bids for a specific project size with a known in-service date.

Q. HOW DOES THE NEED TO CONDUCT AN RFP TO OBTAIN MORE DEFINITIVE PRICING IMPACT THE POTENTIAL IN-SERVICE DATE FOR OFFSHORE WIND (IF IT WERE TO BE SELECTED)?

A. If the Companies received a supportive decision from the Commission by December 31, 2024 to pursue an offshore wind RFP, the Companies project the potential for an offshore wind facility to potentially achieve a 2033 in-service date. Future consideration of offshore wind in the next CPIRP proceeding would likely result in an offshore wind development timeline that supports a 2035 or later in-service date.

Q. ARE THERE ANY ADDITIONAL FACTORS THAT WERE NOT INCLUDED IN THE WEA EVALUATION THAT COULD IMPACT THE

LCOE RESULTS FOR THE PROJECT SCENARIOS AND ASSOCIATED WEAS?

A. Yes. The WEA Evaluation was a quantitative analysis of what would be required to execute an offshore wind project. Many qualitative factors, however, would have to be considered, evaluated, and reconciled to execute an offshore wind project. These include the acquisition of the lease area, negotiation of the cost, how the development of a project would continue, and whether the utility would develop on its own offshore wind project or pursue a build-transfer arrangement with a Developer. As described above, the data provided by the Developers in the WEA Evaluation are non-binding and do not include any Developer costs if a build-transfer scenario were selected. Additionally, if offshore wind were selected as a resource, the Companies would also expect the LCOE estimates would be adjusted to reflect the established in-service date. The WEA Evaluation also did not consider any project execution risks, financing risks, or any risk sharing scenarios. Furthermore, the WEA Evaluation did not reflect hurricane risks, stakeholder risks, or the site maturity of the individual WEAs. All of these qualitative factors could impact the LCOE results for the project scenarios and associated WEAs.

Q. THE COMMISSION DIRECTED THE COMPANIES TO AVOID AFFILIATE BIAS THROUGHOUT THE EVALUATION PROCESS.[14]

[14] Carbon Plan Order at 103.

WHAT STEPS DID THE COMPANIES ADOPT TO PREVENT AFFILIATE BIAS?

A. The Companies were directed to evaluate the three WEAs and leased parcels off the coast of North Carolina including: Kitty Hawk (OCS-A 0508, leased by Avangrid Renewables, LLC) and two in Carolina Long Bay (OCS-A 0545, leased by TotalEnergies Renewables USA, LLC and OCS-A 0546, leased by Duke Energy Renewables Wind, LLC, a current Duke Energy affiliate).[15] As provided in Exhibit 1, to avoid any bias toward their commercial affiliate, the Companies engaged DNV to ensure an impartial process. On February 28, 2022, the Companies hosted a feedback session with the Developers, DNV, and the Public Staff in attendance. During the feedback session, the Companies provided details for the upcoming evaluation process including timeline and scope, and presented an Excel-based RFI file which detailed the specific inputs requested from Developers. DNV, alone, had access to the requested inputs provided by the three Developers during the evaluation process, and DNV was charged with compiling that information without partiality or bias toward or against any Developer or WEA. To that end, the Companies required that all data provided by the Developers be verified and anonymized by DNV prior to being submitted to the Companies. Additionally, throughout the evaluation

[15] The current development efforts of each of the lease areas is not currently known as the Companies do not own any of the lease areas.

process, DNV facilitated any questions between the Developers and Companies in an anonymous fashion to ensure the Companies did not know which Developer raised the question to further avoid any bias in the Companies' provided responses. Upon receipt of the anonymized Verified Inputs, the Companies then performed their calculations of the inputs to put each WEA on an equal footing for comparison purposes in accordance with the Carbon Plan Order. The process and results of this unbiased evaluation are included in Exhibit 1.

IV. CONCLUSION

Q. MESSRS. SMITH, CAPPS, AND POMPEE, DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

DUKE ENERGY

OFFSHORE WEA EVALUATION

I. Background

On May 16, 2022, and in accordance with House Bill 951 ("HB 951"), Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "Duke Energy" or the "Companies") filed their Petition for Approval of the Carbon Plan in Docket No. E-100 Sub 179 (the "initial proposed Carbon Plan"). On December 30, 2022, the North Carolina Utilities Commission ("NCUC" or "Commission") issued its Order Adopting Initial Carbon Plan and Providing Direction for Future Planning ("Carbon Plan Order") in which the NCUC required the Companies to perform an evaluation of the three Wind Energy Areas ("WEAs"). Specifically, the NCUC stated "[t]hat Duke shall study and consider each of the three currently available WEAs off the coast of North Carolina, adopting steps in its evaluation process to protect against any potential affiliate bias, and report the findings of its evaluation of the WEAs to the Commission in its first CPIRP filing." ("Evaluation").[1]

The Commission further determined that the Companies "should commence evaluating the three alternative WEAs . . . [and] study and consider each of the three WEAs off the coast of North Carolina before pursuing acquisition of a leasehold."[2] The NCUC further instructed that the "evaluation should include best estimates of all relevant costs to acquire and develop a WEA and deliver energy to the point of injection into Duke's grid. To the greatest extent practicable, th[e] evaluation should compare the WEAs on a similar basis to one another, including a comparison of the levelized cost of energy to the point of injection into Duke's grid."[3] Additionally, the NCUC acknowledged that the Companies were the right entities to perform the Evaluation, but wanted to protect against any potential affiliate bias throughout the Evaluation process.[4]

In accordance with the Carbon Plan Order, the Companies developed a plan to perform the Evaluation of the WEAs and leased parcels off the coast of North Carolina: Kitty Hawk (OCS-A 0508, leased by Avangrid Renewables, LLC) and two in Carolina Long Bay (OCS-A 0545, leased by TotalEnergies Renewables USA, LLC and OCS-A 0546, leased by Duke Energy Renewables Wind, LLC, a current Duke Energy affiliate). Collectively, the three WEA owners will be referred to as the "Developers." Based on the Carbon Plan Order, the Companies established the below consistent criteria to perform a

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[1] Carbon Plan Order at 133 (Ordering Paragraph No. 26).

[2] Carbon Plan Order at 102.

[3] *Id.*

[4] Carbon Plan Order at 103 ("While the Commission recognizes that third-party studies can provide benefits, the Commission determines that Duke is the proper party to make this evaluation and that a third-party study is not necessary. The Commission notes the potential that the sunk cost of the CLB WEA lease, from the parent company's perspective, may bias the outcome of the decision, and as such, directs Duke to adopt steps in its evaluation process to protect against this potential bias. Further, to the extent there are any near-term development activities in common to all the WEAs under evaluation, including the related onshore transmission infrastructure needed from the point of injection into the Duke grid ad thence inland to load centers, Duke may proceed with these activities.").

comparative analysis of the three WEAs:

- Project export cable landing near Emerald Isle
- Utilize commercially available turbines
- Utilize High Voltage DC cabling for the export cable
- Interconnection at New Bern

As part of the Evaluation process and in order to protect against potential affiliate bias, the Companies retained the services of DNV Energy USA Inc. ("DNV"), an industry expert, to help facilitate the Evaluation by collecting, analyzing, and verifying the various inputs provided by the Developers on "a similar basis to one another."[5] Once received, DNV anonymized the Developer provided inputs prior to submitting to the Companies for modeling. Additionally, DNV facilitated any questions between the Developers and Companies in an anonymous fashion to ensure the Companies did not know which Developer raised the question to further avoid any bias in the Companies' provided responses.

On February 28, 2022, the Companies hosted a feedback session with the Developers, DNV, and the Public Staff in attendance. During the feedback session, the Companies provided details for the upcoming Evaluation process including timeline and scope and presented an Excel-based request for information ("RFI") file which detailed the specific inputs requested from Developers. In addition, an explanation of DNV's evaluation process was described. Questions were answered related to turbine model and point of interconnection assumptions which were to be consistent across all project submissions, particular project input requests, and the specific values which would ultimately be provided to the Companies, subject to appropriate confidentiality protections.

There were no objections raised by the Developers or Public Staff that DNV had the proper expertise to validate inputs and provide aggregated and anonymous results for Duke Energy to evaluate. One developer raised questions about the necessity of having the Developers provide this information. The developer asserted that DNV could use accessible market data and develop the cost estimates for the various projects across the three WEAs with limited inputs from the Developers. The Companies posed the question to all the Developers in attendance, and two of the three Developers felt that the best approach was what the Companies proposed: Developers provide cost data to DNV for validation and anonymized roll-up.

The Evaluation began immediately after the RFI feedback session with the Developers providing contact information for their RFI coordinator. DNV and the Developers then executed Non-Disclosure Agreements governing the process of how DNV would handle the inputs provided by Developers and what DNV could ultimately share with the Companies. DNV set up independent SharePoint sites for each Developer and verified the RFI coordinator was able to access and use the SharePoint securely. During the original RFI period (February 28th to April 5th), there were requests from the Developers

[5] Carbon Plan Order at 102.

for additional time. The Companies, DNV and the Developers worked together to provide an extension for adequate time for the Developers to provide the required information and for DNV to assess the information, including questions and feedback.

DNV completed its evaluation of project inputs provided by Developers between April 17, 2023 and May 5, 2023. The evaluation included clarification emails and calls with each of the Developers. DNV reviewed the development expenses ("DevEx") not including developer fees, capital expenses ("CapEx") and operational expenses ("OpEx") estimates provided for each of the project submissions. DNV benchmarked the major categories of cost against DNV expectations and industry references. In the event the cost assumptions fell outside of observed ranges, DNV identified and discussed with each Developer such discrepancies to better understand any justification for deviations. In the event project assumptions fell outside the observed ranges, and there did not appear to be a reasonable justification for the deviation, DNV suggested an alternative value to the Companies. DNV concluded the following:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

DNV also reviewed energy production estimates provided in each project submission. DNV's review focused on major areas of potential bias including deviations in wind speed estimates from expectations for the region; and review of energy loss estimates to identify areas where DNV's expectations differ. In all cases, DNV identified project energy production assumptions which fell outside DNV expectations. After discussion with the Developers regarding their methodologies, DNV suggested modifications which ranged from a 3.8% decrease to a 2.4% increase in net energy production. It is important to note that these modifications were based on energy production in MW hours, not capacity factor points (the resulting impact on net capacity factor was very small).

II. <u>RFI Analysis</u>

On May 10, 2023, DNV provided the Companies with an anonymized summary analysis of their review of the submittals by the Developers. As requested by the

Companies, each Developer submitted, at minimum, the following three projects:

- An 800 MW project
- A project showing the maximum output supported by the WEAs (assuming 14-15 MW wind turbines)
- A project optimized for cost and size

This approach resulted in nine potential projects that conformed with the Carbon Plan Order criteria as well as design criteria discussed during the RFI Feedback Session utilizing "commercially available wind turbines," "landing site near the Crystal Coast" and "interconnection at the New Bern Substation." In addition to the nine conforming projects, three projects were submitted that did not conform with the requirements because they showed a landing site near Oak Island with interconnection at Brunswick.

In general, the analysis showed that projects become more economical as they increase in size and capacity factor. Only one Developer submitted potential projects that included offshore wind to be available by 2030. Two potential projects were submitted recommending the combination of the two Carolina Long Bay parcels to achieve an approximate 2,200 MW project by 2031-2032.

The information gathered and anonymized by DNV was used by the Companies to create generic offshore wind generation projects (800 MW, 1600 MW, 2400 MW) that did not show preference for certain parcels, but rather used the project size, timing, CapEx and DevEx estimates, energy production estimates, and OpEx estimates provided by the Developers, and input from DNV, to inform the Companies' existing generic offshore wind project costs. The results of the modeling informed the selection of offshore wind in the CPIRP portfolios.

III. RFI Results

DNV obtained the information from the three developers through a non-binding RFI process. Inputs provided by the Developers were verified, anonymized, and provided to the Companies. Several working sessions were held between DNV and the IRP modeling team to ensure inputs provided (including in-service dates, CapEx, DevEx, OpEx, transmission costs, generation profile, and net capacity factor ("NCF")) were interpreted correctly and modelled appropriately. As part of the modeling process, the Companies derived levelized cost of energy ("LCOE") estimates for each of the project submissions.

After the anonymized modeling was completed, through appropriate confidentiality agreements, the Companies requested the names of the Developers and associated WEAs for each project submission to present to the Commission in accordance with the Carbon Plan Order.

In general, the larger capacity projects are estimated to have lower LCOE. This result was expected as significant efficiencies of scale can be realized in offshore wind developments. For example, in general, as turbine units are added to a project, the energy production per unit remains the same, while the CapEx, DevEx, and OpEx cost per unit decreases. However, there is a point of diminishing returns when a given project size necessitates more export cable runs, higher transmission costs, more network upgrades and additional offshore substation(s). This point of diminishing returns is unique to each proposed project given its location, depth, wind resource, conceptual design and other factors. NCF also has a significant impact on LCOE. Given the RFI process called for all projects to propose turbine models commercially available today up to approximately 15 MW, the difference in NCF estimates were primarily driven by the wind resource predicted at each location.

Table 1: Offshore Wind Projects by Project Size and Parcel.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Tables 2 & 3 below show the Companies' estimated LCOE calculations of the conforming projects submitted in increasing order. It is important to note that the costs for the offshore components of a given project submission were based on Developer provided values, while the costs for onshore transmission components and upgrades to the regional transmission system were estimated by the Companies.

Table 2: LCOE of Offshore Wind Projects (without onshore transmission network upgrades). Costs assume 2031 in-service year

[BEGIN HIGHLY CONFIDENTIAL ATTORNEYS' EYES-ONLY INFORMATION]

[redacted]

[END HIGHLY CONFIDENTIAL ATTORNEYS' EYES-ONLY INFORMATION]

Table 3: LCOE of Offshore Wind Projects (including onshore transmission network upgrades). Costs assume 2031 in-service year

[BEGIN HIGHLY CONFIDENTIAL ATTORNEYS' EYES-ONLY INFORMATION]

[redacted]

[END HIGHLY CONFIDENTIAL ATTORNEYS' EYES-ONLY INFORMATION]

IV. Summary

The Companies complied with the Carbon Plan Order directives to conduct an unbiased Evaluation of the existing WEAs and presents the results of that Evaluation for review in this proceeding. The Developers participated in a non-binding RFI process for the Companies to complete the Evaluation. The results of the Evaluation were used by the Companies' modeling team to create a generic offshore wind profile for the 2023 CPIRP proceeding. The results were also used to develop an LCOE between the various parcels and projects.

The Companies' next steps regarding offshore wind resources is addressed in the Chapter 4 Execution Plan and Appendix I to the 2023 Carolinas Resource Plan as filed in the CPIRP proceeding.