STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1181
DOCKET NO. SP-12478, SUB 0
DOCKET NO. SP-12479, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Transfer of Certificates of Public Convenience and Necessity and Ownership Interests in Generating Facilities from Duke Energy Carolinas, LLC, to Northbrook Carolina Hydro II, LLC, and Northbrook Tuxedo, LLC	)))))))))	ORDER ALLOWING DEFERRAL ACCOUNTING, DENYING PUBLIC STAFF'S MOTION FOR RECONSIDERATION, GRANTING TRANSFER OF CPCNs, AND QUALIFYING THE TRANSFERRED FACILITIES AS NEW RENEWABLE ENERGY FACILITIES

HEARD: February 5, 2019, at 10:00 a.m., in Hearing Room 2115, Dobbs Building, Raleigh, North Carolina

BEFORE: Chairman, Edward S. Finley, Jr., Presiding;[1] Commissioners ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray, Daniel G. Clodfelter, and Charlotte A. Mitchell

APPEARANCES:

For Duke Energy Carolinas, LLC:

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[1] Chairman Edward S. Finley, Jr., resigned from the Commission effective June 1, 2019.

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For the Using and Consuming Public:

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BY THE COMMISSION: On July 5, 2018, Duke Energy Carolinas, LLC (DEC or the Company), Northbrook Carolina Hydro II, LLC, and Northbrook Tuxedo, LLC (Northbrook, collectively Applicants) filed a Joint Notice of Transfer, Request for Approval of Certificates of Public Convenience and Necessity (CPCNs), Request for Accounting Order, and Request for Declaratory Ruling (Petition) in the above-captioned dockets.

In summary, Applicants stated that on May 15, 2018, DEC and Northbrook entered into an agreement whereby DEC will sell five hydroelectric generating facilities having a combined capacity of 18.7 megawatts (MW) to Northbrook. Four of the facilities are located in North Carolina, and the fifth is located in South Carolina, as follows:

(1) Bryson Hydroelectric Station, which has a nameplate capacity of 980 kilowatts (kW), is located on the Oconaluftee River in Swain County, and first commenced commercial operation in 1925.

(2) Franklin Hydroelectric Station, which has a nameplate capacity of 1,040 kW, is located on the Little Tennessee River in Macon County, and first commenced commercial operation in 1925.

(3) Gaston Shoals Hydroelectric Station, which has a nameplate capacity of 8.5 MW, is located on the Broad River in Cherokee County, South Carolina, and Cleveland County, North Carolina, and first commenced commercial operation in 1908.

(4) Mission Hydroelectric Station, which has a nameplate capacity of 1,800 kW, is located on the Hiwassee River in Clay County, and first commenced commercial operation in 1924.

(5) Tuxedo Hydroelectric Station, which has a nameplate capacity of 6.4 MW, is located on the Green River in Henderson County, and first commenced commercial operation in 1920.

Applicants stated that DEC’s cost of maintaining these older facilities makes it more economical for DEC to sell the facilities than to continue using them to serve DEC’s ratepayers, and that divestiture of the facilities will not affect DEC’s ability to provide reliable service to its customers at just and reasonable rates. Applicants further stated that DEC will transfer ownership of the facilities to Northbrook for $4,750,000, and that the facilities have a current net book value of $42 million. DEC indicated in its application that approximately $1.6 million of transmission-related work will be required by the sale, as well as $1.0 million in legal and transaction-related costs, and $220,000 in plant material and operating supplies. Further, as part of the transaction, DEC noted that it has agreed to purchase all of the energy and renewable energy certificates (RECs) generated by the subject facilities for five years following the transaction through renewable purchase power agreements (RPPAs) with Northbrook. As such, DEC asserted that through the transaction, the facilities will continue to serve the customers with clean renewable energy, but at a lower cost.

DEC requested that the Commission enter an order allowing DEC to establish a regulatory asset to defer the North Carolina retail allocable portion of the loss on sale, approximately $27 million, to be amortized over a period of years, and with a return, to be set in DEC's next general rate case. In addition, Applicants requested a declaratory ruling that the facilities will be considered new renewable energy facilities, and that DEC can use RECs from the facilities to comply with its obligations under the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). DEC is also seeking to have the CPCNs which were issued or deemed to be issued for the facilities to be transferred from DEC, contingent upon the closing of the transaction to Northbrook.

Moreover, Applicants stated that consummation of the transaction is contingent upon the necessary regulatory approvals by the Commission, the Public Service Commission of South Carolina, and the Federal Energy Regulatory Commission (FERC), and that pending such approvals the transaction is expected to close in the first quarter of 2019. Further, Applicants stated that approval of the requested accounting treatment is a condition to closing the transaction, and, thus, DEC would have no obligation to consummate the sale if the accounting order is not approved. DEC observed that at the time the regulatory asset is approved by the Commission, the facilities will be measured at the lower of carrying amount or fair value less cost to sale and classified as assets held for sale, depreciation of the asset will cease, and the estimated loss will be recorded in the regulatory asset approved by the Commission. In addition, DEC acknowledged that an accounting order granting the relief that DEC seeks will not preclude the Commission or other parties from addressing the reasonableness of the deferred costs arising from the transaction in DEC's next general rate proceeding.

Procedural Background

On July 25, 2018, the Commission issued an order requesting comments from interested parties and reply comments from Applicants.

On September 4, 2018, the Public Staff filed its comments. In summary, the Public Staff stated that it sent multiple data requests to DEC and Northbrook, and held meetings and conference calls with DEC to evaluate the proposed transaction, and that in its communications with the Public Staff DEC indicated that the divestiture of the assets benefited customers through reducing customer risk of increased operations and maintenance (O&M) costs and future capital investments, and minimized future regulatory obligations. The Public Staff stated that it reviewed the preliminary present value of revenue requirements (PVRR) analysis conducted by DEC to compare the option of retaining the facilities with the option of divesting the facilities to a third party and purchasing the energy back from the facilities at avoided cost rates. According to the Public Staff, DEC's analysis showed that the divestiture option was more favorable to customers. The PVRR benefit was disclosed by DEC under seal as confidential information.

The Public Staff stated that in response to data requests DEC indicated that it made capital expenditures on the facilities of approximately $10.25 million in 2015, $6.7 million in 2016, $883,000 in 2017, and spent or has budgeted approximately $865,000 in 2018. The Public Staff questioned whether at the time these costs were being incurred DEC had sufficiently evaluated the magnitude of expenditures required to keep the facilities operational, as opposed to retiring them, or selling them in their prior condition. The Public Staff acknowledged that the Commission completed its investigation of DEC's most recent general rate application and issued its order setting new rates in Docket No. E-7, Sub 1146, on June 22, 2018 (Sub 1146 Rate Order), but stated that it views DEC's proposal to sell the facilities as new information that creates special circumstances meriting further consideration of DEC's proposal to impose the full $27 million loss on sale on ratepayers. As a result, the Public Staff requested that this issue be preserved as an open issue until DEC's next general rate case, when the reasonableness of recovery of the deferred costs will be addressed. In addition, the Public Staff requested that the Commission direct DEC and the Public Staff to further evaluate the reasonableness of the expenditures made by DEC at the facilities during the 36 months leading up to the agreement between the Applicants for the sale of the facilities, to allow these costs for consideration in DEC's next general rate case.

The Public Staff further stated that it reviewed DEC's analysis underlying its decision to sell the facilities, noting that in October 2017 DEC performed a "non-binding market value test," and obtained non-binding bids as a result of that process. The Public Staff stated that DEC reviewed the non-binding offers using several selection criteria, which were disclosed by DEC under seal as confidential trade secret information. Following the initial analysis and screening, a second round of bidding was conducted, which resulted in Northbrook's bid being selected.

The Public Staff also stated that it evaluated the RPPAs between DEC and Northbrook, and found that the avoided cost rates and REC purchase prices were reasonable for the term of the five-year agreement. Further, the Public Staff stated that it evaluated DEC's ability to utilize the RECs generated by the facilities, which will be approximately 59,800, and found that while DEC's September 1, 2017, REPS

Compliance Plan filed in Docket No. E-100, Sub 147, indicates that DEC has contracted for, or has plans to procure, sufficient resources to meet its general requirement for the planning period (2017 to 2019), the REPS general obligations in N.C. Gen. Stat. § 62-133.8(b) increase in upcoming years from 6% to 10%, starting in calendar year 2018, and to 12.5% in calendar year 2021. The Public Staff opined that the avoided cost rates, contract term, and REC purchase price agreed to as part of the transaction and used in the PVRR analysis are reasonable.

The Public Staff stated that it agrees with DEC's proposal to establish a regulatory asset to defer the $27 million North Carolina retail portion of the loss on sale, to be amortized over a period of years, and with a return to be set in DEC's next general rate case, subject to review during that case. However, the Public Staff stated that it does not agree with DEC's proposal to delay beginning amortization of the $27 million until the next rate case. Instead, the Public Staff stated that, as with certain other deferrals and amortizations previously approved by the Commission, the amortization should begin in the month in which the asset transfer is completed, subject to reevaluation and adjustment in DEC's next rate case.

The Public Staff opined that in most cases, even when it is not reasonable to assume that the entire cost underlying a requested regulatory asset is recovered in the rates existing at the time the cost is incurred, and thus deferral and amortization of the cost is appropriate, it is nonetheless not reasonable for the beginning of the amortization of the cost to be delayed until the utility's next general rate case. Further, the Public Staff stated that this approach is most in keeping with the Commission's underlying ratemaking policy that the utility's regulatory books and records should reflect the actual costs of providing utility service to the ratepayers, leaving it up to the utility to decide whether its annual cost of service affects its overall return in a manner that justifies the filing of a general rate case. According to the Public Staff, this approach is also most appropriate when the nature of the underlying cost to be deferred is such that it is best considered in general as a normal part of the cost of conducting utility business, and has been typically used in cases involving the expenses of storm damage repair. The Public Staff cites as the most recent example the Commission's deferral of Hurricane Matthew and other storm damage expenses incurred in 2016 by Duke Energy Progress, LLC (DEP), in DEP's last general rate case, Docket No. E-2, Sub 1142, with the amortization beginning in the month that Hurricane Matthew occurred. The Public Staff also cited the Commission's decision in Docket No. E-7, Sub 828 that amortization of the GridSouth Regional Transmission Organization (RTO) costs should be considered to have begun in June 2002, the date that the GridSouth participants notified FERC that they had ceased incurring GridSouth costs, rather than at the time of DEC's 2007 rate case in Docket No. E-7, Sub 828, as was proposed by DEC. Therefore, the Public Staff recommended that the Commission require DEC to begin amortizing the regulatory asset resulting from the loss on the sale of the hydro facilities as of the date the sale is closed. In addition, the Public Staff stated that based on its review of the average remaining life of the facilities, it recommends that the amortization period for the regulatory asset be set at 20 years, which is comparable to the period of time over which the facilities would have been depreciated if they had remained in service.

With respect to Applicants' request for a declaratory judgment that the facilities will qualify as new renewable energy facilities, and that DEC may use RECs purchased from the facilities for REPS compliance, the Public Staff opined that the transfer of the facilities to Northbrook will result in the electric power from the facilities being delivered to DEC, thereby meeting the criteria under N.C. Gen. Stat. § 62-133.8(a)(5)(c) to be designated as new renewable energy facilities. In addition, the Public Staff recommended that the Commission accept the registration statements filed by Applicants for the facilities.

In conclusion, the Public Staff recommended that the Commission approve Applicants' transaction as requested, with the conditions that DEC's capital expenditures on the facilities are subject to review in DEC's next general rate case, and that the amortization of the loss on sale will begin in the month that the sale of the facilities to Northbrook is completed.

On September 18, 2018, DEC filed reply comments. In summary, DEC stated that the Public Staff's proposal to leave the issue of DEC's prior capital expenditures on the facilities open for review in DEC's next general rate case is unreasonable and should be rejected by the Commission. DEC stated that it first met with the Public Staff to discuss the proposed sale of the facilities on August 23, 2017, two days before DEC filed its rate case application in Docket No. E-7, Sub 1146, and that subsequent meetings were held with the Public Staff to discuss the proposal on February 6, 2018, and May 9, 2018, while the general rate case was pending. Further, DEC stated that it responded to numerous formal and informal data requests from the Public Staff regarding the proposed transaction, and that the Public Staff had more than adequate opportunity to investigate the capital investments made by DEC and to raise them in the Sub 1146 rate case proceeding. According to DEC, allowing the Public Staff to have the ability to review the incurrence of these costs in the next general rate case through hindsight analysis would be contrary to the purpose of the ratemaking process, and would inject unprecedented and impermissible uncertainty into the determination and recovery of just and reasonable costs. DEC cited State ex rel. Utilities Com. v. Conservation Council of North Carolina, 312 N.C. 59, 64, 320 S.E.2d 679, 683 (1984) (citing Utilities Commission v. Intervenor Residents, 305 N.C. 62, 76-77, 286 S.E.2d 770, 779 (1982)), for the principle that a utility's costs are presumed to be reasonable unless challenged, and opined that although the Public Staff knew about the pending transaction it made no challenge to the reasonableness of the facilities' costs in the Sub 1146 rate case proceeding, and should be estopped from doing so in DEC's next rate case. In addition, DEC noted that its requested accounting order would not preclude the Commission or parties from addressing the reasonableness of the deferred legal and transaction costs arising from the sale in DEC's next general rate case.[2]

With regard to the Public Staff's recommendations about the beginning date and length of the regulatory asset amortization period, DEC agreed that it would be appropriate to recognize the amortization expense at the level of depreciation currently

[2] DEC noted that the estimated legal and transaction related costs have increased from the original estimate of $1.0 million and now total approximately $1.4 million.

approved in DEC's rates until the time of its next general rate case, at which time DEC would address the appropriate amortization period for the remaining regulatory asset balance. DEC stated that this approach would result in a slightly higher amortization rate than the Public Staff's proposal, and is reasonable and appropriate.

On November 29, 2018, the Commission issued an Order Requiring Filing of Testimony and Scheduling a Hearing. The hearing was scheduled for Tuesday, February 5, 2019.

On December 21, 2018, DEC pre-filed the testimony and exhibits of Greg D. Lewis, who is on an interim assignment in the Carolinas Regulated Renewables Department; Manu Tewari, Corporate Development Director; and Veronica I. Williams, Rates and Regulatory Strategy Manager. Also on December 21, 2018, Northbrook pre-filed the testimony of John C. Ahlriches, President of Northbrook Energy, LLC.

The transaction was approved by the Federal Energy Regulatory Commission on December 27, 2018. Order Approving Transfer of Licenses, 165 FERC ¶ 62,199.

On January 18, 2019, the Public Staff pre-filed the joint testimony of Dustin R. Metz, Electric Engineer in the Electric Division of the Public Staff, and Michael C. Maness, Director - Accounting Division of the Public Staff. No other parties intervened in the docket.

Also on January 18, 2019, the Public Staff filed a motion for reconsideration of that portion of the Sub 1146 Rate Order that included the capital expenditures on the subject hydroelectric facilities from 2015-2017 in DEC's general rates and requested a finding that the reasonableness and prudency of the capital expenditures can be reviewed in DEC's next general rate case.

On January 28, 2019, DEC filed a response opposing the Public Staff's motion for reconsideration.

On January 30, 2019, DEC, Northbrook, and the Public Staff filed a motion requesting that all evidence be stipulated into the record, that all witnesses be excused from testifying, and that the hearing be cancelled.

On Feb. 1, 2019, the Commission issued an order excusing Northbrook witness John Ahlrichs and DEC witness Manu Tewari from testifying, accepting the stipulation of their testimony into evidence, and accepting two Late-Filed Exhibits. The Commission declined to excuse DEC witnesses Lewis and Williams, and Public Staff witnesses Maness and Metz.

The hearing was held as scheduled on February 5, 2019.

On March 27, 2019, proposed orders were filed by DEC and the Public Staff.

On May 6, 2019, DEC filed a letter informing the Commission that Applicants have entered into a Third Amendment to their sales agreement. DEC stated that the Third Amendment extended the Transaction closing date to August 16, 2019.

Based upon consideration of the pleadings, testimony, and exhibits received into evidence, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. DEC is a public utility with a public service obligation to provide electric utility service to customers in its service area in North Carolina and is subject to the jurisdiction of the Commission.

2. Northbrook is owned by a partnership between the Alliance Fund II, LP and Northbrook Energy, LLC (Northbrook Energy). Northbrook Energy is a privately held independent power producer that has been in the hydroelectric power business for more than 30 years and operates hydroelectric facilities in 12 states, including in North Carolina and South Carolina.

3. Except for the transfer of the CPCN for one facility located in South Carolina, this Commission has jurisdiction over the parties and subject matter pursuant to the Public Utilities Act. A public utility or person must receive a CPCN prior to constructing electric generating facilities pursuant to N.C. Gen. Stat. § 62-110.1 and Commission Rule R8-61(b). A public utility may transfer such certificates and ownership interests pursuant to N.C. Gen. Stat. §§ 62-110(a) and 62-111(a).

4. The Facilities subject to the proposed sale have a combined 18.7-MW generation capacity and consist of the Bryson Hydroelectric Generation Facility in Swain County; the Franklin Hydroelectric Generation Facility in Macon County; the Mission Hydroelectric Generation Facility in Clay County; the Tuxedo Hydroelectric Generation Facility in Henderson County; and the Gaston Shoals Hydroelectric Generation Facility in Cherokee County, South Carolina.

5. After an evaluation of increasing compliance, safety and maintenance costs demonstrated that divestiture of the Facilities would be more cost-effective for customers over time than continued ownership, in May 2017 DEC decided to begin the divestiture process.

6. After soliciting and evaluating offers from potential purchasers, on May 15, 2018, DEC entered into an asset purchase agreement (APA) whereby the Company will sell the Facilities to Northbrook for $4,750,000 (the Transaction). The APA includes certain closing conditions, including an order from the Commission approving transfer of the North Carolina Facilities' CPCNs and approving the establishment of a regulatory asset for the retail portion of any difference between the sales proceeds and the net book value of the plants.

7. The Facilities have a net book value of $42 million. Accordingly, DEC has proposed to sell the Facilities to Northbrook for an estimated loss on sale calculated as the difference between the sale proceeds of $4.75 million and net book value of the Facilities of $42 million, $0.2 million plant material and operating supplies, $1.4 million of legal and transaction-related costs, and $1.6 million of transmission-related work required by the sale. The total estimated loss on the Transaction is $40 million, of which the North Carolina retail allocable portion is $27 million.

8. The sale of the Facilities by DEC to Northbrook and the transfer of the North Carolina CPCNs issued or deemed to have been issued for the Bryson, Franklin, Mission and Tuxedo facilities is in the public convenience and necessity and should be approved, subject to the conditions ordered below.

9. DEC's request for Commission approval of an accounting order for regulatory and accounting purposes authorizing DEC to establish a regulatory asset for the estimated loss on the disposition of the Facilities is appropriate.

10. At the time the regulatory asset is approved by the Commission, the Facilities will be measured at the lower of carrying amount or fair value less cost to sale and classified as assets held for sale. Depreciation of the asset will cease, and the estimated loss will be recorded as a regulatory asset approved by the Commission.

11. It is appropriate for the amortization of the regulatory asset to begin upon the closing of the Transaction.

12. It is appropriate for the amortization expense to be the same as the currently approved depreciation expense for the Facilities, subject to review in DEC's next general rate case.

13. Between 2015 and November 2018, DEC incurred capital expenditures on the Facilities of approximately $17.4 million. More than 95% of the capital costs DEC incurred for the Facilities between 2015 and 2017 were included in net plant in rate base in DEC's general rate case, and were approved by the Commission in its June 22, 2018 order in Docket No. E-7, Sub 1146 (Sub 1146 Rate Order), as having been reasonably and prudently incurred. As a result, the costs are currently being recovered from customers in DEC's rates.

14. DEC met with the Public Staff and discussed the potential sale of the Facilities on August 23, 2017, February 6, 2018, and May 9, 2018. Each of these meetings occurred before or during the pendency of DEC's general rate case in Docket No. E-7, Sub 1146. During these meetings, DEC informed the Public Staff that it expected to sell the Facilities at a loss, that the net book value of the Facilities began to significantly increase beginning in 2015 due to required regulatory spending, and that DEC intended to seek Commission approval to establish a regulatory asset for the retail portion of the loss on the sale of the Facilities.

15. During the general rate case proceeding in Docket No. E-7, Sub 1146, the Public Staff did not bring to the Commission's attention DEC's capital expenditures on the Facilities, DEC's potential sale of the Facilities, or DEC's plan to request deferral of the loss on the sale of the Facilities.

16. The Public Staff's motion under N.C. Gen. Stat. § 62-80 to reopen and preserve the ability of the Public Staff to investigate the 2015-2017 capital costs of the Facilities and hold open the issue of the reasonableness of recovery of these costs until DEC's next general rate case is not supported by a change of circumstances, or any misapprehension or disregard of pertinent facts by the Commission.

17. Once the Transaction is complete and the Facilities have been transferred to Northbrook, each Facility shall qualify as a New Renewable Energy Facility pursuant to the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS) as outlined in N.C Gen. Stat. § 62-133.8.

18. It is appropriate that DEC use any RECs purchased from the Facilities for REPS compliance.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

These findings are informational, procedural, and jurisdictional in nature and are uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-8

The evidence in support of these findings is based upon the Petition and the testimony and exhibits of DEC witnesses Tewari, Lewis, and Williams (DEC witnesses), and the testimony of Public Staff witnesses Maness and Metz (Public Staff witnesses).

The DEC witnesses testified that the Facilities have a combined 18.7-MW generation capacity and consist of the Bryson Hydroelectric Generation Facility in Swain County, North Carolina; the Franklin Hydroelectric Generation Facility in Macon County, North Carolina; the Mission Hydroelectric Generation Facility in Clay County, North Carolina; the Tuxedo Hydroelectric Generation Facility in Henderson County, North Carolina; and the Gaston Shoals Hydroelectric Generation Facility in Cherokee County, South Carolina. In the Petition, DEC stated that it will seek appropriate approval from the Public Service Commission of South Carolina (PSCSC) regarding the Gaston Shoals CPCN.

According to the DEC witnesses, the Facilities are some of the oldest in DEC's portfolio, having entered service more than ninety years ago, as follows: Gaston Shoals began commercial operation in 1908, Tuxedo began commercial operation in 1920, Mission began commercial operation in 1924, and Bryson and Franklin began commercial operation in 1925. The DEC witnesses testified that the combined capacity of the Facilities contributes less than one percent of DEC's hydroelectric generation, and that although these stations were once an important part of the 1900's electrical system, and they served their communities well, today they represent a very small portion of DEC's generating system, and their strategic importance in serving DEC's customers has significantly diminished. Tr., pp. 31-32.

According to the DEC witnesses, due to the significantly escalating compliance, safety, and maintenance costs associated with the small hydro facilities, DEC evaluated a potential sale and determined that divesting these small hydro facilities is more economical than continued ownership and will result in net savings for customers over time. In addition, they testified that the Transaction will allow DEC to optimize its capital investments by focusing on higher priority generation facilities, will eliminate the risk for continued significant investment in the Facilities, and will thereby enhance DEC's ability to provide continued affordable and reliable service to its customers. The DEC witnesses testified that in May 2017 DEC began the divesture process and proceeded to test the market potential. Tr., p. 15; pp. 32-35.

Company witness Lewis described the Present Value Revenue Requirement (PVRR) analysis that DEC performed to determine the benefits of divesting and purchasing back the power of the small hydro facilities versus continuing operation and ownership. He stated that the PVRR assessed future cost probabilities based on current and expected regulatory requirements for equipment maintenance, dam safety, licensing plans and risks, and operations and maintenance. According to witness Lewis, the analysis compared the difference in the present value of the anticipated future costs to the present value of purchasing back the power from a third party, and considered three scenarios that produced a range of amounts in customer benefits. The amounts of benefits and the range were filed by DEC as confidential proprietary trade secret information. Tr., pp. 111-12. Witness Lewis testified that by divesting the Facilities, DEC will only be required to pay for the power produced versus the long-term obligations of ownership and operations, and that the PVRR analysis shows that the sale of the small hydro units will provide significant benefits to customers. Tr., p. 34.

Public Staff witnesses Maness and Metz testified that the Public Staff conducted a detailed review of DEC's PVRR analysis and concluded that it was reasonably performed and indicates "a significant PVRR advantage to disposing of the facilities in the 2018 time frame." Tr., pp. 143-46.

The DEC witnesses testified that after DEC determined in August 2017 that it was more cost effective to sell the hydro units rather than to continue to own and operate them, DEC assembled a core team to develop a project plan and related marketing material for the potential sale using a two-phase process: Phase 1 to invite indicative non-binding offers and Phase 2 to invite binding offers to negotiate a definitive APA. The DEC witnesses stated that Phase 1 of the process concluded on November 15, 2017, with the receipt of non-binding offers from 11 interested parties, and that DEC then evaluated the Phase I offers and moved to Phase 2 of the process with four bidders. According to the DEC witnesses, DEC ultimately negotiated with Northbrook over four weeks, which concluded with the execution of the APA on May 15, 2018. Pursuant to the

May 15, 2018 APA, DEC will sell and transfer the Facilities to Northbrook for $4,750,000. The DEC witnesses testified that the APA includes the following key closing conditions for the Transaction: (1) FERC License Transfer Approval to transfer each of the FERC Licenses to the Purchaser; (2) an order from the Commission approving (i) the establishment of a regulatory asset for the retail portion of any difference between the sales proceeds and the net book value of the plants and (ii) the transfer of the plant CPCNs from DEC to the Purchaser; and (3) an order from the PSCSC (i) granting permission to sell utility property and (ii) approving the establishment of a regulatory asset for the retail portion of any difference between the sales proceeds and the net book value of the plants. In summary, the DEC witnesses noted that approval of the requested accounting treatment is a condition to closing the Transaction, and DEC would have no obligation under the APA to consummate the sale if the accounting order is not approved. According to the DEC witnesses, the deadline for meeting all the closing conditions described above is on or before May 15, 2019, or either party can terminate the agreement. Tr., pp. 15-23.

The DEC witnesses testified that the loss on sale is calculated as the difference between the sale proceeds of $4.75 million and the net book value of the Facilities of $42 million, $0.2 million of plant material and operating supplies, $1.4 million of legal and transaction-related costs, and $1.6 million of transmission-related work required by the sale, and the North Carolina retail allocable portion of the total estimated loss of $40 million is approximately $27 million. Tr., pp. 53-54.

The Public Staff witnesses testified that the PVRR analysis adequately supports DEC's decision to dispose of the Facilities. Tr., pp. 142-143. No other party intervened or opposed the transfers.

CONCLUSIONS

The Commission finds and concludes that approval of the Transaction will serve the public interest by enabling DEC to divest the Facilities and avoid significant, ongoing maintenance costs. DEC has determined that divestiture of the Facilities is more economical than continued ownership and maintenance because it will make it easier for DEC to optimize and prioritize its ongoing investments in higher priority generation facilities, thereby resulting in net savings to customers over time. Further, as part of the Transaction DEC has agreed to purchase all of the energy and RECs generated by the Facilities for five years following the Transaction through renewable power purchase power agreements (RPPAs) with Northbrook. As such, the Facilities will continue to serve customers with clean renewable energy, but at a lower cost over time. In addition, the Commission gives significant weight to the fact that Northbrook Energy has been in the hydroelectric power business for over 30 years, and operates hydroelectric facilities in 12 states, including in North and South Carolina, and is qualified to operate the Facilities. Therefore, the proposed sale of the Facilities, and the transfer of the CPCNs issued or deemed to have been issued for the Bryson, Franklin, Mission, and Tuxedo hydroelectric Facilities will serve the public convenience and necessity, and the Commission concludes that the sale should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-12

The evidence in support of these findings is based upon the Petition and the testimony and exhibits of DEC witnesses Williams and Lewis, and the testimony of Public Staff witnesses Maness and Metz.

Company witness Williams described DEC's request for an accounting order authorizing DEC to establish a regulatory asset for the estimated loss on the disposition of the Facilities (calculated as the difference between the sale proceeds and net book value of the Facilities, plant material and operating supplies, transaction-related costs and transmission-related work required by the sale). She testified that DEC proposes to amortize the regulatory asset over a period of time and at the approved return, as determined in DEC's next general rate case. Further, she stated that at the time the regulatory asset is approved by the Commission, the cost of the Facilities will be removed from plant in service, the appropriate amounts reflecting the sale will be recorded as assets held for sale, depreciation of the assets will cease, and the estimated loss will be recorded in the regulatory asset approved by the Commission. According to witness Williams, absent the accounting treatment requested, DEC would be forced to write off the North Carolina retail allocation of approximately $27 million for the loss associated with the sale of the Facilities if DEC were to proceed with the Transaction. As previously noted, approval of the accounting treatment is a condition to closing the Transaction. Tr., pp. 53-54.

DEC witness Williams further testified to the deferral standard the Company recommends that the Commission utilize in considering its request. Witness Williams acknowledged the two-prong test which according to her the Commission "sometimes utilizes," consists of: (1) whether the costs in question are unusual or extraordinary in nature and (2) whether absent deferral the costs would have a material impact on the Company's financial condition. However, she suggested the Commission's test should not apply to the Company's request in this docket because this transaction is unique in that it is not like the typical situation for which deferral is sought. She discussed Docket No. E-7, Sub 828, in which the Commission approved deferral and amortization of costs related to another atypical set of facts concerning work performed to establish the GridSouth Regional Transmission Organization (RTO), which was subsequently discontinued as a result of a change in FERC regulatory policy. According to witness Williams, the Commission decided that the costs in question were "clearly unusual and not part of the ordinary cost of providing service," and further noted that the amounts at issue were "clearly material," citing comparable past deferrals ranging from approximately $15 million to $40 million. She added, however, that the Commission's analysis in that case went beyond the limited question of materiality. In the GridSouth matter, the Commission noted that for any item of cost the nature and scope of deferral and amortization are committed to the Commission's sound discretion. Witness Williams further testified that the net costs (i.e., loss) associated with the potential sale in this case qualify for deferral consistent with other tests previously applied by the Commission in similar situations, and such tests are still relevant today. It was her opinion that the sale of generating assets is not part of the conduct of a utility's ordinary course of business and would not normally be reflected in any given general rate case. Further, she opined that the loss associated with this sale is not immaterial in the context of other deferrals and costs itemized in general rate case proceedings. Finally, she stated that allowing the deferral and amortization of the prudently-incurred costs required to achieve the future benefits of lower costs of service provides an equitable balancing of the interests of customers and the Company's shareholders. Witness Williams stated that it is DEC’s position that because customers received the benefits of the units under regulation, it is appropriate that the loss resulting from the sale should be included in the Company’s cost of service and recovered over a reasonable period of time, particularly here where customers will receive an ongoing benefit due to decreased cost of service in the future. Tr., pp. 55-57.

Public Staff witnesses Maness and Metz testified that the Public Staff agrees in part with DEC witness Williams' statement that the Commission's two-prong deferral test should not apply to this request based on the unique or atypical nature of the transaction at issue. Consistent with the Public Staff's comments filed on September 4, 2018, witnesses Maness and Metz testified that the Public Staff agrees it is reasonable for the Commission to consider the apparent benefit of this transaction to the ratepayers, and in its discretion to authorize the creation of a regulatory asset and amortize it to expenses over a period of time, subject to review in DEC's next general rate case. However, they testified that the Public Staff does not agree that the transaction is *otherwise* [outside of apparent benefit and the Commission's discretion] unusual or large enough to merit deferral based on the Commission's two-prong test. They described the two-prong test as follows: (1) "whether the costs in question are unusual or extraordinary in nature, and (2) whether absent deferral, the costs would have a material impact on DEC's financial condition." Tr., pp. 150-51.

According to witnesses Maness and Metz, the types of costs to which this or a similar test is applicable typically fall into one of the following categories:

1. Major storm repair expenses that are relatively unusual and so large in magnitude (often expressed as an impact on earnings) that it is not reasonable to presume that the expenses are being recovered in then-current rates.

2. Other unexpected expenses or losses so obviously unusual in nature and large enough in magnitude (often expressed as an impact on earnings) that it is not reasonable to presume that the expenses/losses are being recovered in then-current rates.

3. Other expenses or losses that may not be so unusual in nature but are so excessively large in magnitude (often expressed as an impact on earnings) that it is not reasonable to presume that the expenses/losses are being recovered in then-current rates.

Witnesses Maness and Metz testified that the expense/loss under consideration in this proceeding does not fall into any of the categories listed above, in that it occurred as a result of a transaction taken in the normal course of business and is therefore not unusual, nor is it large enough in magnitude to automatically be considered a properly deferrable item in the absence of some other underlying rationale justifying deferral. Finally, they further noted that the expense/loss is not large enough in magnitude to be considered a major driver of a general rate case. Tr., pp. 151-52.

Witnesses Maness and Metz testified that despite the deferral, in their opinion, failing the two-prong test, deferral of the costs at issue is justified because of the nature of the actions that gave rise to the loss and the costs that make up the loss. The witnesses viewed the Company's actions as ceasing utility operation of the Facilities and engaging in a transaction that is expected to reduce the future cost of service (and thus, implicitly or explicitly, customers' rates) to a level below what would have been experienced in the absence of the action(s), regardless of costs incurred in the past. Witnesses Maness and Metz stated that the book loss recorded as part of the sales transaction is made up of those past costs incurred (net of closure and sales-related expenses) in a manner that was prudent and reasonable, but which have not yet been recovered in rates, and that past costs reasonably and prudently incurred generally remain reasonable and prudent, regardless of the Company's later decisions about future costs. Since the sale of the hydro units is expected to be the best forward-looking action for the Company to take, and since the loss consists of past prudently incurred costs, the Public Staff's opinion in this specific case is that it is reasonable for the unrecovered past costs (the loss) to be preserved for continued recovery in rates (subject to reasonable and appropriate amortization in the interim and subject to further investigation of the reasonableness and prudence of the 2015-2018 expenditures). Despite its opinion that the transaction and resulting loss fail the Commission's two-prong deferral test, the Public Staff stated that the appropriate regulatory accounting mechanism to achieve preservation of the costs is deferral of the loss by way of a regulatory asset. Tr., pp. 153-54.

As to the amortization period, DEC witness Williams testified that because depreciation of these assets is currently in rate base, it is appropriate to continue to recognize amortization expense at the level of depreciation expense currently in rates until DEC's next general rate case, at which time DEC would address the appropriate amortization period for the remaining regulatory asset balance. As such, the Company proposed approval of the regulatory asset, with amortization beginning at the time the regulatory asset is recorded on the books, at a rate equivalent to the remaining 20-year life of the assets. Once established, the Company would plan to address the proper amortization period for the then-remaining regulatory asset balance in its next general rate case. Further, witness Williams stated DEC's position is that it is appropriate for amortization to begin at the time that the regulatory asset is recorded on the books and not at the completion of the Transaction. Tr., p. 58.

The Public Staff witnesses recommended to the contrary that the Commission require DEC to begin amortization in the month in which the Transaction closes, subject to re-evaluation and adjustment in the next general rate case. Further, the Public Staff recommended that the amortization period for the regulatory asset be set at approximately 20 years, which it asserts is the average remaining book life of the

Facilities, but should be subject to re-evaluation and adjustment in the Company's next general rate case. Tr., pp. 157-61. In their testimony, Public Staff witnesses Maness and Metz explained that although there might be slight differences between the annual amounts of amortization expense recorded under the Company's proposal and the Public Staff's proposal, the Public Staff considers the Company's proposal reasonable. Tr., p. 161.

DISCUSSION

The Commission has historically treated deferral accounting as a tool to be used only as an exception to the general rule, and its use has been allowed sparingly. Cost deferral is an exception to the principle of matching current costs with current revenues because it delays the recovery of a cost until a future reporting period and it may result in the delayed recognition of such costs until the utility begins receiving increased revenues as a result of its next general rate case. Deferrals of increased or decreased costs result in customers being charged or benefitted, respectively, in future periods for spending experiences associated with providing service in earlier periods, while deferrals of increased or decreased revenues result in customers benefitting or being charged, respectively, in future periods for receipt of income by the utility associated with providing service in earlier periods.

The Commission's justification for approving cost deferral, and thereby departing from the general rule of matching current costs with current revenues, is to grant the utility relief from an unexpected cost that, absent deferral, would materially reduce the utility's earnings. Thus, the Commission has often applied a two-prong test to consider whether a requested cost deferral is justified: (1) whether the costs in question are unusual or extraordinary in nature, and (2) whether, absent deferral, the costs would have a material impact on the utility's financial condition. Under the first prong of the test, the Commission has required that deferrals be justified on the basis of an unusual or extraordinary event or change of circumstance. Revenues or costs can be unusual or extraordinary either because of their occurrence or size, or both. Thus, the purpose of the first prong of the cost deferral test is to prevent the utility's financial viability from being harmed by an increased cost that the utility could not have anticipated or otherwise protected itself from incurring. The concept is that the utility should not be penalized in its effort to earn its authorized rate of return when it incurs unusual costs.

The purpose of the second prong of the cost deferral test is to determine whether in fact the utility needs the benefit of cost deferral in order to protect its financial viability from the detrimental impact of an unexpected cost.

In the current proceeding, DEC suggests that the loss on sale is unusual and unique in nature and that the Commission's two-prong test should not be applied, as DEC believes the unique nature of the sale transaction as a whole makes the test an imperfect if not inappropriate determinant of the decision to allow or deny deferral of costs. The Company points to the GridSouth RTO docket as being a similarly unique transaction, and surmises that the Commission applied a balancing test (not the two-prong test) to determine whether deferral and amortization was equitable to both ratepayers and shareholders.[3] In addition, DEC argues that the current loss on sale is not immaterial in the context of other deferrals approved by the Commission, that the loss on sale is a prudently incurred cost to achieve least-cost service, and that allowing the deferral will achieve an equitable balancing of the interests of ratepayers and shareholders. DEC's witness Williams further points out that if the sale had resulted in a gain, the Commission would expect DEC's customers to receive at least a portion of the gain.[4]

The Public Staff posits that the transaction at issue is not otherwise unusual or large enough to merit automatic deferral under the two-prong test. Nonetheless, the Public Staff makes the argument that due to the apparent benefit of the sale transaction to ratepayers it is reasonable for the unrecovered costs (the loss) to be preserved for continued recovery in rates and, thus, the appropriate regulatory accounting mechanism to achieve this preservation is deferral of the loss by way of a regulatory asset.

The Commission agrees with DEC that the GridSouth cost deferral issue presented a unique set of facts. In October 2000, DEC, Progress Energy Carolinas, Inc. (now Duke Energy Progress, LLC), and South Carolina Electric & Gas (collectively, GridSouth participants), began the formation of GridSouth in compliance with FERC Order 2000 requiring transmission owning utilities to join or form a RTO. For various reasons, mostly beyond the control of the GridSouth participants, the participants suspended their formation efforts in June 2002. In the GridSouth Order, the Commission addressed DEC's request to defer $ 43.9 million in GridSouth costs to be recovered from North Carolina retail ratepayers. Even though the Commission acknowledged that the GridSouth situation was essentially "one of a kind," *i.e.* uniquely atypical, the Commission nonetheless, contrary to DEC's urging in the instant case, applied the two-prong cost deferral test. After concluding that both prongs of the test were satisfied, the Commission balanced the equities and allowed deferral of the GridSouth costs in part, the total North Carolina retail deferral being about $29 million. GridSouth Order, at 53-57. Thus, the Commission determined the test was met and then balanced the equities in determining the appropriate size or amount of the deferral.

In the present case, the sale transaction, and resulting loss, is no more atypical than the "one of a kind" formation of GridSouth. The atypical nature of the costs in the GridSouth matter did not make the two-prong test inapplicable to the question of deferral; thus, DEC is misguided in offering GridSouth for the proposition that the two-prong test should not be applied in deciding whether to allow DEC's request for an accounting order to establish a regulatory asset for the loss on sale of the Facilities.

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[3] Order Approving Stipulation and Deciding Non-Settled Issues, Docket No. E-7, Sub 828 (Dec. 20, 2007) (GridSouth Order).

[4] For electric utilities, the Commission has generally concluded that a gain on the sale of property that has been used in providing service to the utility's customers should be passed through to the utility's ratepayers and , conversely, that a loss on the sale of utility property should be treated as a cost to be paid by the utility's ratepayers. See Order Ruling on Proper Accounting Treatment to Record the Transfer of Certain Utility Assets, Docket No. SP-122, Sub 0 (May 20, 1999).

When the two-prong test is applied to the present facts, the Commission is persuaded that the first prong of the test is met because the sale of these hydroelectric generating facilities is an unusual event. A utility's transfer of generating capacity is not a frequent occurrence, and not one that can typically be planned so as to coincide with a general rate case. In a comparable situation, where the timing of bringing on new generation could not be planned to coincide with a general rate case, the Commission has allowed deferrals of the cost of new generating plants that began commercial operation in between rate cases or during a rate case. See Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, Docket No. E-22, Sub 532, at 63-67 (Dec. 22, 2016); Sub 1146 Rate Order, at 77-78. However, regarding the second prong of the cost deferral test, the Commission cannot find that the loss, absent deferral, will have a material impact on DEC's financial condition. DEC made no effort to quantify the impact of the $27 million loss on sale on DEC's current financial condition. DEC has not provided substantial evidence to meet the second prong of the cost deferral test and, therefore, DEC has not established that deferral should be allowed on the basis of the Commission's two-prong deferral test.

Still, even though the Commission does not agree that its two-prong deferral test is inapplicable to the loss on sale in this case, and despite its conclusion that DEC did not prove deferral was justified using the test, the inquiry on DEC's request does not end here. Both DEC and the Public Staff have correctly pointed out, albeit in different fashion, that the cost deferral test is not the exclusive factor in considering a deferral request. The Public Staff argued it is appropriate that the Commission consider the benefit of the transaction at issue to the ratepayers and exercise its discretion to create a regulatory asset, while DEC argued that equities at play in this transaction lend themselves to a balancing of lower costs of service in the future against delayed recognition of past costs for historical service that are collected in future periods. The Commission does not apply the two-prong test in a vacuum. Rather, the Commission considers all of the pertinent factors involved on a case-by-case basis, and weighs the equities to arrive at a decision that is fair to the utility and its ratepayers, and that serves the public interest. Thus, in the case at hand, the Commission is not unduly restricted to the results of applying the two-prong test. The Commission may analyze the merits of deferral using not only the well-established two-prong test but also considering the totality of the underlying facts, circumstances, and equities of this case, as discussed below.

Substantial evidence in this case establishes that the sale of the hydro plants to Northbrook, coupled with DEC's buy back of the power under the RPPA, is a least cost avenue for DEC to serve its ratepayers. As a result, ratepayers will experience a benefit from the sale and RPPA with Northbrook that will be reflected in DEC's future rates due to DEC's resulting lower cost service. The Commission gives significant weight to this evidence.

In addition, the Commission gives significant weight to the evidence presented by witness Lewis that these hydro plants will require capital expenditures by DEC in the near future. Witness Lewis testified that once DEC made the decision to sell the plants, it put on hold projects that could be delayed, and notified prospective buyers that they would need to complete these projects. Tr., pp. 39-40. As previously noted, witness Lewis testified that these plants' combined capacity of 18.7 MW contributes less than one percent of DEC's hydroelectric generation. Tr., pp. 31-32. As a result of the sale to Northbrook, ratepayers will avoid the cost and risk of making capital expenditures on these very old assets that get relatively little use in providing electricity on DEC's system. The Commission deems that result to be an important benefit to ratepayers.

Moreover, there is substantial evidence that the cost of retiring these hydro plants would be substantial. Witness Lewis testified to these costs in the context of DEC's decision to relicense the plants, as opposed to surrendering the licenses.

> [Y]ou would be exposed to significant costs associated with the environmental costs, environmental assessments potentially required to remove the dams – remove the dams, remove the sediment, dispose of the sediment…So all you have effectively done when you retire the units is you've retired the revenue-making portion of that. You haven't gotten rid of any of the risks of dam safety or the compliance risks.

Tr., p. 72.

Witness Lewis also testified to DEC's actual experience in removing a small dam.

> [D]uring the relicensing process you may recall a very small dam called Dillsboro that they [FERC] did recommend and order us to remove that dam. It was only a 10 or a 12-foot high dam, a very small dam, and we did remove that but only after lengthy litigation and studies were required. So we did surrender that license but it was quite painful.

Tr., p. 92.

As a result of the sale, ratepayers will avoid the cost and risk of retiring these five plants, a cost and risk that could be faced by DEC and ratepayers in the near future given the age of these assets. Again, based on the relatively small contribution that these plants make to DEC's provision of electric service, the future retirement of the plants is potentially an albatross, and should be avoided if reasonably possible. The Commission gives significant weight to the evidence that DEC's ratepayers will be spared the risk of this albatross by DEC's sale of the plants.

CONCLUSIONS

Accordingly, with respect to deferral of the loss on sale, in the final analysis the Commission's decision is guided by the overriding principle that the rates set by the Commission should be just and reasonable to ratepayers and to DEC. N.C.G.S. § 62-130. On one side of that balance, the Commission recognizes that the sale of the hydro plants, even at a loss, is expected to reduce DEC's future cost of service below what would be incurred in the absence of the sale. The substantial reduction of these costs is a significant benefit for ratepayers. On the other side of the balance, the deferral of the loss on sale would be a benefit for DEC, at some future cost to ratepayers, since absent deferral DEC would have to absorb the loss on sale within its current rates. Balancing the equities in favor of ratepayers and those in favor of DEC, the Commission concludes that the significant present and future benefits that will inure to ratepayers as a result of the sale outweigh the relatively small cost that ratepayers will incur in the future due to the deferral of the loss on sale. Therefore, the Commission determines that DEC's request to defer the loss on sale should be approved.

Based on the foregoing and the record, the Commission finds and concludes that DEC’s loss on the sale of the hydro plants to Northbrook should be treated as a cost of service and assigned to DEC’s ratepayers. Further, the Commission finds and concludes that the public interest will be served by allowing DEC to establish a regulatory asset for deferral of the loss on sale of the hydroelectric generating facilities to Northbrook.

With regard to the period of time over which to amortize the regulatory asset, the Commission has discretion; however, the purpose of deferral accounting is not to preserve costs for an indefinite period of time. Only in extraordinary circumstances, or in cases where a general rate case is pending, and when the Commission particularly wants to synchronize the recognition of a deferred cost and the approval of new rates, is the delay of beginning an amortization generally appropriate. Typically, when the nature of the underlying cost to be deferred is such that it is best considered in general as a normal part of the cost of conducting utility business, the Commission will require that the amortization begin when the related event/transaction occurs. For example, the deferral of storm costs in DEP’s last general rate case in Docket No. E-2, Sub 1142, where the Commission required amortization to begin in the month the largest storm costs were incurred. The Commission deems this approach to be reasonable and appropriate as it best keeps with the basic ratemaking policy that a utility's regulatory books and records should reflect the actual costs of providing utility service to the ratepayers (including the reasonable amortization of periodically deferred costs), and that it should be up to the utility to decide whether that annual cost of service affects its overall return in a manner that justifies the filing of a general rate case. The Commission considers these sale transaction costs to be of a somewhat similar nature, and thus part of the normal cost of conducting utility business. For these reasons, the Commission finds and concludes that the amortization period in this situation should begin in the month in which the asset transfer is completed such that the amortization of the deferred costs into the cost of service begins upon their incurrence.

Further, the Public Staff recommended an amortization period of 20 years, which is the average remaining book life of the facilities, i.e., comparable to the period of time over which the facilities would have been depreciated if they had remained in service. In its reply comments DEC asserted that because depreciation on these assets is currently approved in rates, DEC agrees that it would be appropriate to recognize amortization expense at the level of depreciation currently approved in rates until the time of its next general rate case, at which time DEC would address the appropriate amortization period for the remaining regulatory asset balance. DEC also noted that its proposed treatment of amortization expense actually results in a slightly higher expense than the Public Staff's proposal. In testimony, the Public Staff stated that it considered the Company's proposal reasonable. Based upon the foregoing, the Commission finds and concludes that the amortization expense should be recognized at the annual level of depreciation expense currently approved in rates subject to re-evaluation and adjustment in DEC's next general rate case proceeding. Amortization of the regulatory asset should begin in the month the sale is closed.

In summary, the Commission concludes that the loss on the sale of the hydro plants to Northbrook should be treated as a cost of service and assigned to DEC's ratepayers, and that DEC's request to establish a regulatory asset for the loss on the sale should be approved, as the sale is in the interest of ratepayers. Further, amortization of the regulatory asset should begin at the time the Transaction is closed and be amortized at the level of depreciation currently approved in rates until the time of DEC's next general rate case. The amortization period for the remaining regulatory asset and the question of whether it should earn a return will be decided in DEC's next general rate case. Finally, the Commission notes that its decision on deferral of the loss on sale is based on the particular facts of this case, and should not be cited or relied on as precedent for future cost deferral decisions.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-16

The evidence in support of these findings is based upon the Petition and the testimony and exhibits of DEC witnesses Lewis and Williams, the joint late-filed exhibits, and the testimony of Public Staff witnesses Maness and Metz.

Between 2015 and November 2018, DEC incurred capital expenditures on the Facilities of approximately $17.4 million. DEC witness Lewis testified in detail as to the projects and pointed out that they were required to comply with license obligations, dam safety requirements, and personnel safety. Tr., pp. 35-39, 86-87, 123-24; Lewis Exhibit 2; Joint Partially Confidential Late-Filed Exhibit Nos. 1 and 2. Company witness Lewis made the analogy to the Model T Ford, which was produced in the same general timeframe of 1908 to 1925 when the Facilities were commissioned, and when many regulatory agencies such as the Federal Energy Regulatory Commission (FERC) and the Environmental Protection Agency did not exist. Witness Lewis explained that as FERC license and environmental regulations evolved over the decades, small hydro facilities, regardless of their small generating capability, their antiquated designs, and their lack of economies of scale, were required to comply with continuously evolving regulations, standards, and expectations. Tr., pp. 36-37.

DEC witness Lewis testified to the lengthy FERC relicensing process for the Gaston Shoals, Bryson, Franklin and Mission facilities. He stated that the Company made the decision to relicense the Gaston Shoals facility in the 1990 timeframe and received the new FERC license in 1996, and that the decision to relicense the Bryson, Franklin and Mission facilities was made in the 1999-2000 timeframe, but the new FERC licenses were not received until 2011. Tr., pp. 82-83; Joint Late-Filed Exhibit 2, DEC Response to

Public Staff DR 7-3. According to witness Lewis, during the lengthy FERC relicensing process DEC asked FERC to allow it to delay making an investment in the units until it determined if new licenses would be issued and, if so, what the new conditions would be. Witness Lewis offered examples of the "onerous" new FERC license conditions the Company received, including maintaining lake levels within one and a quarter of an inch. Tr., pp. 84, 121-22; Joint Late-Filed Ex. 1, DEC Responses to Public Staff DR 6-3 and 6-4. He testified that after receiving the new FERC licenses in 2011, the Company went through a two-year period of engineering and design work, and thereafter, with FERC's approval, staggered the work necessary to complete the projects required to comply with the new FERC licenses. Tr., pp. 99-102, 122-23.

Company witness Lewis testified that none of the approximately $17.5 million in capital projects was incurred to make the units more attractive to a potential buyer. Tr., pp. 124, 128. Furthermore, he testified that none of the projects were initiated for the primary purpose of upgrading the units. Instead, any upgrade was a secondary benefit of replacing aging, deteriorated equipment with modern replacements as a means of reliably managing flows and staying in compliance. Tr., p. 40. Witness Lewis explained that the Facilities' capital costs were significantly lower in 2017 and 2018, after the Company put some projects on hold due to their pending and notified prospective buyers that such projects would need to be completed after acquisition. Tr., pp. 39-40; Joint Late-Filed Ex. 1.

According to witness Lewis, more than 95% of the capital costs DEC incurred for the Facilities between 2015 and 2017 were included in net plant in rate base in DEC's last general rate case and were approved by the Commission in its June 22, 2018 order in Docket No. E-7, Sub 1146. He stated that the remaining capital costs were mostly associated with a project that was suspended pending the sale. Tr., pp. 37-39, 59; Lewis Ex. 2.

Public Staff witnesses Maness and Metz acknowledged that the approximately $17.5 million of the costs at issue in this docket are 100% capital costs. Tr., p. 188. They testified to the extensive investigation the Public Staff conducted into DEC's 2015-2017 capital expenditures at the Facilities in this docket, including multiple data requests and "multiple detailed meetings and conference calls with DEC personnel regarding these investments." Tr., pp. 148-49. Nevertheless, they stated that the Public Staff concluded it was "unable to determine if the costs were for timely compliance with license and safety requirements, reflected capital projects that were deferred from previous years that were made to secure the sale of the assets, or other reasons." Id.

On January 18, 2019, the Public Staff filed a motion requesting that the Commission conclude that the reasonableness of the loss on sale, including the reasonableness of the capital expenditures from 2015-2017, can be reviewed in DEC's next general rate case. The Public Staff summarized the parties' discussions about the hydro facilities prior to and during the Sub 1146 general rate case. It contended that "The proposed hydroelectric sale was too remote, uncertain, and lacking in quantification at the time of the Public Staff's rate case investigation to put the Public Staff on notice that a detailed investigation of prior investment in those facilities was needed." Motion of the Public Staff, at 4-5. The Public Staff submitted that the Commission should reconsider the prudence of the hydro plant capital expenditures pursuant to N.C.G.S. § 62-80, based on changed circumstances.

DISCUSSION

Pursuant to N.C.G.S. § 62-80

> The Commission may at any time upon notice to the public utility and to the other parties of record affected, and after opportunity to be heard as provided in the case of complaints, rescind, alter or amend any order or decision made by it. Any order rescinding, altering or amending a prior order or decision shall, when served upon the public utility affected, have the same effect as is herein provided for original orders or decisions.

The Commission's decision to rescind, alter or amend an order upon reconsideration under G.S. 62-80 is within the Commission's discretion. State ex rel. Utilities Comm'n v. MCI Telecommunications Corp., 132 N.C. App. 625, 630, 514 S.E.2d 276, 280 (1999). However, the Commission cannot arbitrarily or capriciously rescind, alter or amend a prior order. Rather, there must be some change in circumstances or a misapprehension or disregard of a fact that provides a basis for the Commission to rescind, alter or amend a prior order. State ex rel. Utilities Comm'n v. North Carolina Gas Service, 128 N.C. App. 288, 293-294, 494 S.E.2d 621, 626, rev. denied, 348 N.C. 78, 505 S.E.2d 886 (1998).

The Public Staff conceded that DEC met with the Public Staff on August 23, 2017, to discuss the proposed sale of the facilities, but stated that DEC provided only a "bare outline of the sale proposal." Motion of the Public Staff, at 4. The Public Staff further stated that DEC provided it with a second update on the potential sale in February 2018, which was more than a month after the discovery period ended in DEC's Sub 1146 rate case, and was after the Public Staff had filed its testimony. In addition, the Public Staff cited the Supreme Court's definition of retroactive ratemaking in State ex rel. Utilities Comm'n v. Nantahala Power & Light Co., 326 N.C. 190, 205, 388 S.E.2d 118, 129 (1990), and contended that it is not requesting retroactive recovery of revenues from DEC, but, rather, it is requesting that the Commission make an adjustment to the amount of the recoverable loss on sale if it finds that the capital improvements were not prudent or reasonable.

On January 28, 2019, DEC filed a response to the Public Staff's motion for reconsideration. In summary, DEC stated that it not only met with the Public Staff several times to discuss the potential sale of the hydro plants, but that it also responded to approximately 75 data requests and participated in numerous conference calls with the Public Staff regarding the proposed transaction. DEC further stated that the Public Staff's motion is weakened because even after extensive fact gathering the Public Staff has not alleged any facts or pointed to any evidence that it contends demonstrates that any of the capital expenditures were imprudent or unreasonable. In addition, DEC cited State ex rel. Utilities Comm'n. v. Edmisten, 291 N.C. 575, 581-82, 232 S.E.2d 177, 181, (1977), and State ex rel. Utilities Comm'n. v. Carolina Water Service, 335 N.C. 493, 498, 439 S.E.2d 127, 129-20 (1994), for the proposition that a motion for reconsideration under N.C.G.S. § 62-80 must be filed within 30 days after the Commission's order is issued. Moreover, DEC submitted that the question of whether the capital improvements were prudent has no relationship to the issue of whether the sale of the hydro plants should be approved.

The Commission does not accept DEC's position that a motion for reconsideration under N.C.G.S. § 62-80 must be filed within 30 days after the Commission's order is issued, for three reasons. First, the plain wording of the statute is that "The Commission may at any time ... rescind, alter or amend any order or decision made by it." (Emphasis added). Second, the notion that the changed circumstances on which the Commission could act under N.C.G.S. § 62-80 must occur within 30 days after the date of the Commission's order would eviscerate the usefulness of the statute, i.e. a changed circumstance occurring 31 days or later after the Commission's order could not be used as a grounds for reconsideration. Third, in the cases cited by DEC the Supreme Court did not hold that there is a 30-day limit on motions for reconsideration under N.C.G.S. § 62-80.

According to the Public Staff, there are three steps in the reconsideration process under N.C.G.S. § 62-80,[5] with the first step being

> [a] hearing on evidence or change of conditions that might justify altering a prior order… The Public Staff's motion in the instant case does not require the filing of evidence. The evidence, if any, would be presented at step two; there is no requirement in N.C. Gen. Stat. § 62-80 for the Public Staff to make the case at this time.

Public Staff's Proposed Order, at 10.

The above statement is not correct. The first inquiry under N.C.G.S. § 62-80 is whether there is a change in circumstances or a misapprehension or disregard of a fact that provides a basis for the Commission to rescind, alter or amend the Sub 1146 Rate Order. In Sub 1146, the bulk of the capital expenditures on the hydro plants from 2015-2017 was included in DEC's cost of service. Neither the Public Staff, nor any other party, challenged the reasonableness or prudence of the capital expenditures. As a result, a prima facie case was made that these costs were reasonably incurred. State ex rel. Utilities Comm'n. v. Intervenor Residents, 305 N.C. 62, 76-77, 286 S.E.2d 770, 779, (1982). As a result, in the Sub 1146 Rate Order the Commission approved DEC's recovery of the capital expenditures on the hydro plants, and those capital expenditures are today being recovered by DEC in its current rates as a depreciation expense on the plants.

[5] The Public Staff did not file a post-hearing brief. This discussion of the Public Staff's position on reconsideration is based on points made in the Public Staff's proposed order.

The Commission agrees with the Public Staff that on the question of reconsideration under N.C.G.S. § 62-80 the Public Staff is not required to provide evidence that the capital expenditures were unreasonable or imprudent. However, in order for the Commission to reopen the inquiry into whether DEC should be allowed to continue to recover those expenditures - either in DEC's current rates, as they are presently being recovered, or as a part of the loss on sale of the plants - the Public Staff must provide some evidence that there has been a change of circumstances, or a misapprehension or disregard of the facts regarding the Commission's approval of DEC's recovery of the capital expenditures in the Sub 1146 Rate Order.

In addition, the Commission agrees with the Public Staff that DEC's characterizations of the post-rate case discovery and information exchange as including "an incredible number of data requests," and requiring copious amounts of witness Lewis' time are inapposite. Again, the question of whether the capital expenditures on the Facilities were reasonable and prudent is not before the Commission at this point.

Similarly inapposite is the Public Staff's position that DEC's inclusion of the statement, "An accounting Order granting the relief that DEC seeks will not preclude the Commission or parties from addressing the reasonableness of the costs deferred arising from the Transaction in the next general rate case" in DEC's Petition was a stipulation by DEC that the Commission could inquire into the reasonableness of the capital expenditures in DEC's next rate case. The statement is not ambiguous in its reference to the "costs deferred arising from the Transaction," in that DEC obviously did not include the capital expenditures, costs already in its rates and being recovered from ratepayers, as "costs arising from the Transaction." Moreover, it does not appear that the Public Staff suffered from such a misunderstanding, or was misled in any way, since the Public Staff included in its initial comments in this docket its arguments for reopening the inquiry into the reasonableness of the capital expenditures.

In addition, the Commission finds unpersuasive the Public Staff's contention that reopening the inquiry into the capital expenditures would reflect "the normal practice of the Commission when ruling on deferral requests." Public Staff's Proposed Order, at 11. The Commission is unaware of a prior instance in which it has ordered deferral of utility costs that are currently being recovered in the utility's rates, and the Public Staff cited no such instance. Indeed, such an order would be an anomaly, as the purpose of cost deferral is to preserve unusual costs for recovery by the utility in its next rate case. In the present case, DEC's capital expenditures were not unusual costs, the reasonableness of the costs has already been determined by the Commission in the Sub 1146 Rate Order, and the costs are presently being recovered in DEC's rates.

The question before the Commission is whether the Public Staff had a reasonable opportunity during the rate case to understand and in some manner address the significance of the capital expenditures on the hydro plants in relation to DEC's plan to sell the plants. The Public Staff and DEC presented evidence about the meetings on the potential sale of the hydro plants, and the information that was provided by DEC to the Public Staff immediately prior to the filing of the Sub 1146 rate case, during the rate case, and during this proceeding. The Public Staff's and DEC's evidence does not differ in any material respects, and the Commission will not recount it in detail here. The Commission finds the crucial portion of the evidence to be the meetings on August 23, 2017, and February 6, 2018. During the August 23 meeting, DEC informed the Public Staff that its PVRR analysis showed divestiture was positive for customers, the expected forced regulatory spend was significantly contributing to net book value growth and that the sale price for the plants was expected to be less than the current net book value. Lewis, Tr. pp. 115-17; Joint Late-Filed Ex. 1, DEC Response to Public Staff DR 6-11; Maness and Metz, Tr. pp. 189-90. On February 6, 2018, DEC again met with the Public Staff to provide an update on the sale, including the status of bids it had received to date. In that meeting, slides provided to the Public Staff stated, "Non-binding offers imply expected proceeds from divestiture to be considerably lower than net book value of the assets; if DEC agrees to sell the assets, it plans to make a regulatory asset request for the retail portion of the stranded costs." Lewis, Tr. p. 118. During the meeting, DEC also informed the Public Staff that the net book value of the hydro plants was approximately $42 million. Id. Witness Lewis testified that there was a give-and-take discussion between DEC and the Public Staff. Id. at 116.

CONCLUSIONS

The Commission, the regulated utilities, and the Public Staff have one common purpose – to serve the public interest. The Commission and parties may differ on how to meet that purpose, but in the end the public interest is best served when all participants in the ratemaking process are provided timely and adequate information about the manner in which ratepayers will be served and the cost of providing that service. In the present case, DEC witness Tewari testified that in December 2017 DEC moved into the second and final phase of the sale process by inviting four of the 11 bidders who submitted non-binding offers for the Facilities in Phase 1 to submit binding offers.

> [T]he decision to move these four bidders into Phase 2 created the right balance between the ability to support the detailed due diligence effort (host management presentations, provide responses to bidder questions, conduct site visits for each bidder) and to ensure receipt of at least one binding offer from a bidder that met the criteria described in the response to the prior question upon conclusion of the Phase 2 due diligence the [sic] process.

Tewari, Tr. p. 19.

On March 5, 2018, DEC sent binding bid instructions to the four Phase 2 bidders. Tewari, Tr. p. 20. The hearing in the Sub 1146 rate case began on March 5, 2018. Thus, on the date that the hearing began DEC was reasonably certain that it would sell the Facilities for a loss and request a deferral of the loss on sale. The Commission notes that, although not required of DEC, it would have been helpful to the Commission had DEC worked with the Public Staff to bring this situation to the attention of the Commission, and to request the Commission's guidance on whether and how potential issues about the capital expenditures and deferral of the loss on sale should be addressed, or preserved for later consideration.

The Commission agrees with the Public Staff that the Public Staff was put in a difficult position when it received the hydro sale information late in the rate case process, and too late for the Public Staff to effectively conduct discovery on the details of DEC's plan to sell the hydro plants, or to pre-file testimony on the issue. Nevertheless, the Commission is not persuaded that there is a change of circumstances, or a misapprehension or disregard of a fact that supports reconsideration of that portion of the Sub 1146 Rate Order that approved DEC's capital expenditures on the hydro plants. The Commission appreciates the dilemma in which the Public Staff found itself after being informed on the eve of the rate case that DEC was contemplating selling the hydro plants. As the Public Staff noted, electric rate cases are huge proceedings that involve thousands of pages of documents, and present multiple and immediate complex issues. For this reason, the Commission does not fault the Public Staff for being unable to piece together timely discovery or testimony on this potential issue during the pendency of the rate case. On the other hand, the issue was not hidden from the Public Staff. Indeed, DEC flagged the issue, albeit late in the process, for the Public Staff's attention. As previously noted, the hearing in the rate case began on March 5, 2018, and it lasted several days. The Commission concludes that the Public Staff had a reasonable opportunity to ask DEC questions about the hydro capital expenditures and DEC's potential sale of the plants during the rate case hearing. At a minimum, the Public Staff could have brought the issue to the Commission's attention and requested the Commission’s guidance on how to preserve the issue for later investigation by the Public Staff and consideration by the Commission. In addition, the Public Staff could have requested that the approval of DEC’s recovery of the capital expenditures be conditional, that the amount received in rates for these costs be placed in a deferred account, and that the deferred account be subject to being used as an off-set to the loss on sale. The Public Staff did not follow any of these possible courses for preserving the issue of the reasonableness and prudency of DEC’s capital expenditures. Based on the foregoing and the record, the Commission finds and concludes that there has been no showing of a change of circumstances, or any misapprehension or disregard of pertinent facts that provides the basis for a reconsideration of the Commission’s approval of DEC's capital expenditures on the hydro plants in the Sub 1146 Rate Order. As a result, the Public Staff’s motion for reconsideration should be denied.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17-18

The evidence in support of these findings is based upon the Petition and the record as a whole.

DEC has agreed to purchase all of the energy and RECs generated by the Facilities for five years following the Transaction through the RPPAs with Northbrook. As such, after the Transaction the Facilities will continue to serve customers with clean renewable energy, but at a lower cost over time. In accordance with the Commission’s

June 23, 1995 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 74, DEC and Northbrook filed form RPPAs for the Facilities agreed to by DEC and Northbrook, which will be entered into by the parties at the closing of the Transaction. In its comments, the Public Staff recommended that the Commission grant the Applicants' requested declaratory ruling that the Facilities are new renewable energy facilities, and that DEC can use the RECs to meet its REPS obligations.

Pursuant to N.C. Gen. Stat. § 62-133.8(b)(2), an electric public utility such as DEC may meet its REPS compliance requirement through several methods, including by "generat[ing] electric power at a new renewable energy facility" or "purchasing renewable energy certificates from a new renewable energy facility." In addition, the definition of a new renewable energy facility in N.C. Gen. Stat. §62-133.8(a)(5)(c) includes "a hydroelectric power facility with a generation capacity of 10 megawatts or less that delivers electric power to an electric power supplier."

The Commission accepted the registration of many of the DEC-owned hydroelectric facilities of less than 10 megawatts as renewable energy facilities, but not as new renewable energy facilities, in its Order Accepting Registration of Renewable Energy Facilities in Docket Nos. E-7, Subs 886, 887, 888, 900, 903, and 904 (July 31, 2009); and its Order Accepting Registration of Renewable Energy Facilities, in Docket Nos. E-7, Subs 942, 943, 945, and 946 (December 9, 2010) (Registration Orders). In the Registration Orders, the Commission specifically cited its June 17, 2009 Order on Public Staff's Motion for Clarification in Docket No. E-100, Sub 113, where it concluded that these utility-owned hydroelectric facilities do not, however, meet the delivery requirement of N.C. Gen. Stat. §62-133.8(a)(5)(c), which requires the delivery of electric power to an electric power supplier, such as DEC, by an entity other than the electric power supplier in order to qualify as a new renewable energy facility. In this case, the transfer of the Facilities to Northbrook will result in the electric power from these hydroelectric facilities, all of which are less than 10 megawatts in capacity, being delivered to DEC, thereby meeting the statutory criteria to be designated as new renewable energy facilities.

As part of the Petition, Northbrook filed registration statements for each of the hydroelectric facilities as new renewable energy facilities. The Public Staff reviewed the registration statements and determined that they contain the certified attestations required by Commission Rule R8-66(b). Therefore, the Public Staff recommended that the Commission accept the registration statements for each of the Facilities.

CONCLUSIONS

Based on the foregoing, the Commission concludes that the transfer of certificates for the Facilities from DEC to Northbrook is justified by the public convenience and necessity and should be approved, and that the certificates shall be issued to Northbrook upon the closing of the Transaction. Further, the Commission authorizes DEC to establish a regulatory asset for the loss on sale of the Facilities, with the period of amortization and the issue of a return on the deferred balance to be decided in DEC's next general rate case. In addition, the Commission finds and concludes that once the Facilities have been transferred to Northbrook, each Facility shall qualify as a new renewable energy facility pursuant to the REPS statute, and that DEC may use any RECs purchased from the Facilities for REPS compliance.

IT IS, THEREFORE, ORDERED as follows:

1. That the transfer of the Bryson, Franklin, Mission, Tuxedo, and Gaston Shoals hydroelectric generating facilities by DEC is hereby approved. The transfer of CPCNs which were issued or deemed to have been issued to DEC for the Bryson, Franklin, and Mission facilities to Northbrook Carolina Hydro II, LLC, and the transfer of the CPCN which was issued or deemed to have been issued for the Tuxedo facility from DEC to Northbrook Tuxedo, LLC, are approved, contingent upon the closing of the Transaction.

2. That DEC's certificates for the four North Carolina hydroelectric generating facilities are hereby cancelled and reissued to Northbrook upon the closing of the Transaction.

3. That DEC shall notify the Commission and the Public Staff within 10 days of the date of closing the Transaction.

4. That DEC shall provide the Commission and the Public Staff with the accounting entries related to the Transaction within 60 days of the date of closing the Transaction.

5. That DEC is hereby authorized to establish a regulatory asset for the loss on the disposition of the hydro units of approximately $27 million on a North Carolina retail allocable basis. Amortization of the regulatory asset shall begin at the time the Transaction is closed and amortization expense shall be at the level of depreciation currently approved in rates until the time of its next general rate case, at which time DEC shall address the appropriate amortization period for the remaining regulatory asset balance. The amortization period for the remaining regulatory asset and the question of whether it should earn a return will be decided in DEC's next general rate case.

6. That the Public Staff's motion under N.C.G.S. § 62-80 to reopen and preserve the ability of the Public Staff to investigate the 2015-2017 capital costs of the Facilities and hold open the issue of the reasonableness of recovery of the costs until DEC's next general rate case shall be, and is hereby, denied.

7. That, for ratemaking purposes, the issuance of this Order is without prejudice to the right of the Public Staff or any party to take issue with the reasonableness of the deferred costs arising from the Transaction itself and their treatment for ratemaking purposes in DEC's next general rate case.

8. That DEC may use RECs purchased from the Facilities for REPS

compliance.

9. That Northbrook's registration statements for the Facilities are accepted upon completion of the transfer.

10. That the Commission's decision on deferral of the loss on sale is based on the unique facts of this case, and shall not be cited or relied on as precedent in future proceedings.

ISSUED BY ORDER OF THE COMMISSION.

This the 5th day of June, 2019.

NORTH CAROLINA UTILITIES COMMISSION

A. Shonta Dunston

A. Shonta Dunston, Deputy Clerk