BEFORE THE
PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

APPLICATION OF
DUKE ENERGY PROGRESS, LLC FOR AUTHORITY TO ADJUST AND INCREASE ITS ELECTRIC RATES AND CHARGES

DOCKET NO. 2022-254-E

DIRECT TESTIMONY OF
ERIC BORDEN

ON BEHALF OF
SOUTH CAROLINA DEPARTMENT OF CONUMER AFFAIRS

COAL ASH REMEDIATION COST RECOVERY

December 1, 2022

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name, title, and business address.

A. My name is Eric Borden. I am a Principal Associate at Synapse Energy Economics ("Synapse"), located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q. Please state your educational achievements and professional designations.

A. I have a bachelor's degree in finance from Washington University in St. Louis and a master's in Public Affairs from the University of Texas at Austin. My resume is attached as Exhibit EB-1.

Q. Please describe your relevant experience.

A. I have worked on numerous utility cost recovery proceedings related to review of forecast and incurred costs in general rate cases, reasonableness reviews, and other types of utility cost recovery applications. My previous testimony has addressed ratemaking alternatives including disallowances when I have found costs were not reasonably incurred.

I have testified on numerous occasions at the California Public Utilities Commission (CPUC) and recently submitted testimony in Illinois related to two investor-owned utilities addressing electric vehicle infrastructure plans and cost recovery, including the appropriateness of regulatory asset treatment for certain expenses.[1] Since joining Synapse, I have contributed to projects and testimony on regulated utility issues in California, Illinois, Maine, New Hampshire, New Mexico, and Minnesota.

Q. Have you previously testified before the Public Service Commission of South Carolina?

A. No.

Q. On whose behalf are you providing this testimony?

A. I am testifying on behalf of the South Carolina Department of Consumer Affairs ("DCA" or "Department").

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my testimony is to discuss cost recovery options for Duke Energy Progress' ("Duke", "DEP" or "Company") incurred coal combustion residual ("CCR" or "coal ash") removal costs related to both basin closures and basins at active coal power plants. Specifically, I provide illustrative options for cost recovery related to "coal ash basin closure" for which the Company seeks regulatory asset treatment.[2] The Company refers to these costs as "asset retirement obligation" or "ARO" costs.[3]

[1] Commonwealth Edison Company in Docket 22-0432/22-0442 (Consol.). Direct Testimony of Eric Borden and Courtney Lane on Behalf of The People of the State of Illinois, AG Ex. 1.0, September 22, 2022, pp. 54-58.
[2] Direct Testimony of Rachel Elliott at 22:20 and Table on page 23.
[3] Id.

I also address options related to the Company's requests to capitalize and recover revenue requirements for what the Company calls "non-ARO [asset retirement obligation]" environmental costs "associated with coal ash" and "related to the continued operation of active plants."[4] These costs appear to be similar to those incurred for coal ash basin closure, except they relate instead to operational coal plants. My analysis of CCR cost recovery options related to basin closure and at operational plants is also relevant to the Company's request to treat CCR removal costs as a regulatory asset going forward. [5]

Q. Are there issues related to the company's coal ash removal expenditure request that you do not address in your direct testimony?

A. I do not provide an opinion on whether coal ash removal costs were prudently incurred, though I find below this issue warrants further investigation and should be considered by the Commission. I also do not provide an opinion on whether coal ash removal costs are required pursuant to federal law, which is an issue before the Commission in this application.

Q. What coal ash related expenditures and cost recovery mechanisms does DEP propose to recover in this case?

A. DEP seeks to recover CCR removal expenditures related to coal ash basin closure at "legacy sites" (ARO) as CCR removal costs at active plants (non-ARO). DEP seeks regulatory asset treatment for $73 million of ARO costs on a South Carolina basis, which adds approximately $14 million in carrying costs to this incurred amount.[6]

[4] Direct Testimony of Rachel Elliott at 26:6-7.
[5] Direct Testimony of Rachel Elliott at 42.
[6] Direct Testimony of Rachel Elliott at 22-23; 26-27.

The Company proposes to capitalize $28 million in non-ARO costs at active plants on a South Carolina basis, for which it seeks five years of revenue requirement in this proceeding—approximately $9 million in carrying costs and $3 million of depreciation expense in total.[7] The remainder of these costs, constituting around $25 million,[8] plus carrying costs (estimated in Section IV), would presumably be collected in the future.

The Company also resubmitted coal ash related costs that were previously disallowed by the Commission. The total costs sought related to these activities are shown below.

Table 1. Coal Ash Remediation Costs
($ Thousands, South Carolina Basis)[9]

Legacy Sites (ARO)	$ 86,462
Resubmission (Previously Disallowed)	$ 29,258
Active Plants (Non-ARO)	$ 12,220
Insurance Proceeds, net of legal fees	$ (8,884)
Total	$ 119,056

The Company proposes to amortize the previously disallowed costs and ARO costs over seven years, and it seeks to amortize non-ARO costs over a three-year period.[10]

[7] Elliott Exhibit 4, SC5030-2 Deferral (Supplemental).
[8] $28 million total incurred coal ash remediation costs less $3 million in depreciate expense (South Carolina basis).
[9] Elliott Exhibit 4, Excel workpapers SC 4010; 5030.
[10] Direct Testimony of Rachel Elliott at 25:12; 26:21.

Q. Does DEP request any other Commission action regarding coal ash remediation costs?

A. Yes. DEP seeks an accounting order to treat "coal ash basin closure compliance costs after the cut-off date for this rate case" as a regulatory asset.[11]

Q. Please summarize your findings.

A. Based on the discussion and research below, I find the following:

1. There were numerous instances that led to environmental violations and potential health hazards by the coal ash basins for which the Company now seeks cost recovery of remediation expenditures..
2. Based on review of South Carolina and other jurisdictions, the Commission has significant discretion in how coal ash remediation costs may be recovered from ratepayers, ranging from no return up to the utility's Weighted Average Cost of Capital (WACC).
3. DEP has not adequately supported its proposal to recover legacy coal ash remediation costs (ARO) as part of a regulatory asset.
4. DEP has not adequately supported its proposal to capitalize coal ash remediation costs (non-ARO) at active plants.
5. Coal ash remediation costs are more akin to operation and maintenance (O&M) costs, not capital costs, as they do not represent investment in used and useful plant.
6. Regulatory asset treatment of coal ash remediation costs at legacy plants (ARO) adds $14 million in carrying costs to the incurred costs for these activities, while capitalization of coal ash remediation costs at active plants (non-ARO) adds around $31 million in carrying cost.

Q. Based on these findings, what are your recommendations?

A. I recommend the following:

1. The Commission should follow fundamental principles of cost recovery when it considers how and if coal ash remediation costs should be recovered.
2. The Commission should consider partial or full disallowances of coal ash remediation costs.
3. The Commission should not allow a rate of return for coal ash related remediation costs.

[11] Direct Testimony of Rachel Elliott at page 41:15-17.

Q. How are the remaining sections of your testimony organized?

A. The remaining sections of testimony discuss why there is sufficient publicly available evidence that the Commission should consider disallowances of coal ash remediation costs. I then discuss options for cost recovery, assuming the Commission grants either partial or full cost recovery. I include research from Commission decisions in other states and calculations to illustrate total cost recovery from ratepayers based on a range of returns that may be considered by the Commission.

II. THE COMMISSION SHOULD CONSIDER A PARTIAL OR TOTAL DISALLOWANCE OF COAL ASH REMOVAL COSTS

Q. What argument does Duke make in support of its full recovery of costs?

A. Duke argues that it should recover its CCR costs because they were reasonably and prudently incurred in order to meet the requirements of applicable environmental laws and obligations.[12]

Q. Does DEP's description of why it should recover coal ash remediation costs adequately describe the considerations that should be made by the Commission in this case?

A. No. I recommend the Commission primarily consider several known principles of cost recovery to guide its ultimate decision. These include the following, discussed further in case law and in the National Association of Regulatory Utility Commissioners' (NARUC) "Coal Ash Law and Commercialization" study: (1) Known and Measurable

[12] Direct testimony of Jessica Bednarcik at 4.

Principle; (2) Just and Reasonable Principle; (3) Prudency Principle; (4) Used and Useful Principle; (5) Cost Causation Principle; and (6) Expenses/Property Distinction.[13]

Q. Do you agree that Duke's CCR costs have been reasonably and prudently incurred?

A. I do not provide an opinion on this matter. However, I believe that a full or partial disallowance should, at minimum, be considered by the Commission based on publicly known information about these coal ash sites, discussed below.

Q. What factors have other Commissions taken into consideration in the context of coal ash cost recovery relevant to this case?

A. In 2020, the North Carolina Supreme Court found that the North Carolina Utilities Commission ("NCUC") was required to "evaluate the extent to which the utilities committed environmental violations" when setting the utility's rates, "even if any such violations did not result from imprudent management."[14] The cases in question, which involved coal ash issues related to Duke Energy Progress and Duke Energy Carolinas, were remanded to the NCUC for further consideration of these elements. Although this case was in North Carolina, the South Carolina Public Service Commission should consider whether South Carolina ratepayers deserve similar protections based on the fact-specific circumstances of the CCR removal costs at issue here.

[13] National Association of Regulatory Utility Commissioners (NARUC), *A Comprehensive Survey of Coal Ash Law and Commercialization,* January 2020, https://pubs.naruc.org/pub/A6923B2D-155D-0A36-31AA-045B741819EC, pp. 79-86. *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591 (1944) *Bluefield Water Works and Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923).

[14] *State v. Stein*, 851 S.E.2d 237, 375 N.C. 870 (N.C. 2020). Available at https://casetext.com/case/state-v-stein-64.

Q. Do DEP's coal ash ponds at issue here pose risks to nearby residents and the environment?

A. This appears to be the case, as nine out of the ten coal ash ponds in this case contain ash in contact with groundwater.[15] Coal ash is known to contain chemicals like mercury, cadmium, arsenic,[16] and multiple other contaminants which have been linked to severe health issues including cognitive and developmental delays, lung disease, cancer, and birth defects.[17]

Groundwater studies show that despite a clay liner, wastewater has migrated out of at least one of the ash basins, "leading to groundwater exceedances around the basin's boundary."[18] All of the basins are at risk of leakage due to environmental disasters; "the ash basins at both Weatherspoon and Sutton are constructed in areas classified as seismic impact zones" and are "unstable."[19] Others, particularly H.F. Lee, which was built in a floodplain, have a demonstrated vulnerability to floods, as I will describe below.[20]

The danger presented by these coal ash basins was so great that the NC DEQ required Duke in 2016 to provide households within one-half mile of six of the coal-fired power plants with coal ash basins at issue here with bottled drinking water.[21] In 2016, North Carolina passed an amendment to the 2014 Coal Ash Management Act that required

[15] Direct Testimony of Jessica Bednarcik at 12.
[16] Environmental Protection Agency (EPA), *Coal Ash Basics*, https://www.epa.gov/coalash/coal-ash-basics (last updated March 6, 2022).
[17] NARUC, *A Comprehensive Survey of Coal Ash Law and Commercialization,* January 2020, https://pubs.naruc.org/pub/A6923B2D-155D-0A36-31AA-045B741819EC, p. 16, Figure 6.
[18] Direct Testimony of Jessica Bednarcik at 13.
[19] Direct Testimony of Jessica Bednarcik at 17.
[20] Direct Testimony of Jessica Bednarcik at 17.
[21] North Carolina Department of Environmental Quality, "Release: DEQ Completes Permanent Replacement of Water Supplies at Coal Ash Sites" (October 12, 2018). Available at https://deq.nc.gov/news/press-releases/2018/10/12/release-deq-completes-permanent-replacement-water-supplies-coal-ash. Six of the seven plants at issue here are in North Carolina, the other, Robinson, is in South Carolina.

Duke to supply permanent clean water solutions to affected households due to potential contamination of drinking water.[22] Duke also offered households a financial payout if residents were willing to release Duke from future liability.[23] The Company's 2017-2020 expenditures on bottled water and other permanent solutions to potentially contaminated drinking water can be found in the Table below.

Table 2. Duke Energy Progress Drinking Water Expenditures September 2017 – January 2020[24]

Coal Plant	2017	2018	2019	2020	Total
Asheville	$17,479	$139,627	$265,558	$10,776	$433,441
H.F. Lee	$46,636	$485,972	$4,726	$1,810	$539,144
Mayo	$58,507	$312,279	$91,862	$10,237	$472,885
Roxboro	$178,383	$1,675,053	$405,804	$38,835	$2,298,075
Sutton	$10,140	$226,769	$50,651	$3,537	$291,097
Weatherspoon	$12,922	$164,342	$99,644	$11,726	$288,635
Grand Total	*$324,068*	*$3,004,042*	*$918,245*	*$76,922*	*$4,323,276*

Q. Have these risks resulted in environmental damage and potential harm to residents of North and South Carolina?

A. Yes. The coal ash basins at issue here have a history of environmental damage. Since 2015, coal ash basins at all seven of the coal-fired power plants under examination in this docket have experienced some kind of flood, leak, or other discharge into the surrounding environment. For example, in 2015, South Carolina's Department of Health and Environmental Control, plus attorneys with the Southern Environmental Law center, filed a letter saying that ash had penetrated 18 feet below the water table at Robinson and that

[22] North Carolina House Bill 630: Drinking Water Protection/Coal Ash Cleanup Act (2016). Available at https://www.ncleg.gov/Sessions/2015/Bills/House/PDF/H630v4.pdf.

[23] Elizabeth Ouzts, "Duke Energy's coal ash offer causing confusion, concern" Energy News Network. (February 16, 2017). Available at https://energynews.us/2017/02/16/duke-energys-coal-ash-offer-causing-confusion-concern/.

[24] DEP NC 2019 Rate Case, Permanent Water Supply Solutions, Public Staff DR 104-1, December 2019. Totals include expenditures for both bottled water and permanent water solutions at coal units with ash basins at issue in this docket.

groundwater levels showed unsafe levels of arsenic.[25] That same year, Duke plead guilty to intentional, unauthorized discharge of coal ash waste into waters of the United States, including from Asheville and H.F. Lee.[26] In 2016, the NC DEQ issued twelve Notices of Violation to Duke for allowing wastewater to leak from coal ash basins at coal-fired facilities—five of which are relevant to this cost recovery request (Asheville Steam Station, Lee Steam Electric Plant, Mayo Steam Electric Power Plant, Roxboro Steam Electric Plant and Weatherspoon Steam Electric Plants).[27] That same year, H.F. Lee experienced additional flooding from the nearby Neuse River, prompting the NC DEQ to issue a letter requesting that Duke investigate how much coal ash was released.[28] Again, in 2018, H.F. Lee was flooded, submerging its coal ash ponds for days and potentially exposing surrounding waterways to toxic chemicals. Sutton also experienced flooding, resulting in the spillage of 2,000 cubic yards of coal ash into the nearby Lake Sutton, which ultimately breached its dam and released its contents into the Cape Fear River.[29]

Q. Why should this history cause the commission to consider disallowances?

A. It may not be reasonable for a utility to recover costs that are incurred only after the utility has caused irreparable health and environmental damages to surrounding residents

[25] Samantha Lyles, "Arsenic at Robinson Plant ash basin raises alarms" News and Press. (April 1, 2015). Available at https://www.newsandpress.net/arsenic-at-robinson-plant-ash-basin-raises-alarms/.

[26] United States of America v. Duke Energy Business Services LLC, Duke Energy Carolinas, LLC, Duke Energy Progress, Inc. No. 5:15 CR-62-H; 5:15 CR-67-H; 5:15 CR-68-H (North Carolina 2015). Available at https://www.justice.gov/file/438651/download.

[27] Wayne Barner, "Duke Responds to Coal Ash Basin Violations, Cites Progress" Power Engineering. (March 7, 2016). Available at https://www.power-eng.com/emissions/duke-responds-to-coal-ash-basin-violations-cites-progress/#gref.

[28] Shalina Chatlani, "Duke asked to determine extent of coal ash spill following flooding at HF Lee plant" Utility Dive. (October 25, 2016). Available at https://www.utilitydive.com/news/duke-asked-to-determine-extent-of-coal-ash-spill-following-flooding-at-hf-l/428942/.

[29] Kendra Pierre-Louis, et al., "Florence's Floodwaters Breach Coal Ash Pond and Imperil Other Toxic Sites" (September 24, 2018). Available at https://www.nytimes.com/interactive/2018/09/13/climate/hurricane-florence-environmental-hazards.html?mtrref=undefined&gwh=046B568D8FAC162803D85A462A40A0DF&gwt=pay&assetType=PAYWALL.

and communities. As discussed by the North Carolina Supreme Court, even if coal ash basins have largely been compliant with the law and in keeping with standard practice does not mean all costs should be recovered from ratepayers. Past history of material hazardous impacts warrant consideration in cost recovery applications like this one.

If the Commission does not disallow all costs and finds partial or full cost recovery is warranted in this case, I provide options to accomplish this below.

III. THERE ARE MULTIPLE LOWER COST OPTIONS FOR RECOVERY OF COAL ASH REMOVAL COSTS

Q. What is the Company's cost recovery proposal for coal ash remediation costs?

A. DEP states it has incurred $73 million for coal ash removal costs on a South Carolina basis for legacy plants (ARO), and DEP proposes to treat these costs as a regulatory asset. Regulatory asset treatment, which assumes these costs are part of utility rate base and thus earn a return at the Company's approved Weighted Average Cost of Capital (WACC), adds an additional $14 million, for a total of $87 million.[30] The utility requests to amortize this amount over seven years.[31]

Similarly, the Company requests to capitalize $28 million incurred from 2019-2021 on a South Carolina basis at active plants (non-ARO),[32] for which it seeks around $12 million of revenue requirement in this rate case, amortized over the next three years. This $12 million consists of $9 million in carrying costs and $3 million of depreciation expense.[33] However, the Company proposes to recover most of the remaining incurred costs over the

[30] Direct Testimony of Rachel Elliott at 23:9-12.
[31] Direct Testimony of Rachel Elliott at 25:12.
[32] Elliott Exhibit 4, SC 5030-1.
[33] Elliott Exhibit 4, SC 5030-1.

next 14 to 53 years, along with carrying costs.[34] Therefore, the impact of capitalizing these costs, if granted, will have a long-term effect on ratepayers. This impact is estimated in Section IV.

Q. Why does the Company propose to treat coal ash removal costs as a regulatory asset or as capitalized expenditures?

A. This is not entirely clear from direct testimony. In response to discovery, the Company states that regulatory asset treatment "ensures that the Company only recovers from customers its actual level of spending related to coal ash compliance expenditures."[35] The Company further admits it "has not evaluated any other cost recovery mechanisms related to South Carolina retail coal ash compliance expenditures"[36] other than regulatory asset treatment.

Regarding capitalization of CCR removal costs at operational plants, the Company's testimony only states these "are capitalized to plant in service."[37]

Q. What is your response to these arguments?

A. They do not adequately support the utility's proposals. Indeed, the Company's statement that a regulatory asset "only recovers from customers its actual level of spending" is inaccurate—as described above and seen below, it also involves payment of $14 million in carrying costs.

Regarding coal ash remediation at active plants, the costs in question are not traditional capital expenditures. Capital expenditures represent the "net amount of investment in the

[34] Based on effective depreciation rates as of June 2021. Elliott Exhibit 4, SC5030-3.This information was not clearly provided in the Company's testimony.
[35] Data request SCDCA 3-1(b).
[36] Data request SCDCA 3-1(c).
[37] Direct Testimony of Rachel Elliott at 26:8.

utility's plants and other assets that are committed to rendering electricity service to customers, i.e., they are used and useful."[38] By contrast, coal ash remediation costs are not investments in long-lived assets like power plants or distribution lines necessary for the generation and delivery of power to customers. Instead, they are more akin to operation and maintenance (O&M) expenses, which must be incurred to reliably operate utility system equipment but do not represent "used and useful" plant.

The Commission has flexibility with regard to how coal ash remediation costs may be recovered from ratepayers, and is not limited to regulatory asset or capitalization, as the Company's testimony seems to imply.[39] The Commission in South Carolina, as well as other jurisdictions, have recognized this, as discussed further in the ensuing section.

A. Treatment of Deferred Expenses in South Carolina and Other Jurisdictions

Q. Has the South Carolina Commission opined on the issue of how to treat deferred expenses?

A. Yes. In a recent Order, the Commission stated its finding that expenses need not earn a return, and that, ultimately, the Commission can apply its own discretion regarding how to recover these costs:

> The ORS Position, which was adopted by this Commission, is that deferrals related to O&M expenses are not to earn a return, while those deferrals related to capital costs are to earn a return. Treatment of deferrals is ultimately a matter of the Commission's discretion.[40]

---

[38] NARUC, *A Comprehensive Survey of Coal Ash Law and Commercialization,* January 2020, https://pubs.naruc.org/pub/A6923B2D-155D-0A36-31AA-045B741819EC, p. 83.
See also, *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591 (1944)
Bluefield Water Works and Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923).

[39] In addition, as discussed above, the Company admits in discovery regarding regulatory asset treatment it "has not evaluated any other cost recovery mechanisms related to South Carolina retail coal ash compliance expenditures."
[40] 2018-318-E, Order No. 2019-454, October 18, 2019, p. 15.

While the utility may propose regulatory asset (or any other) cost recovery treatment, the Commission has discretion to decide what is in the best interest for South Carolina ratepayers using its judgement and based on the specific circumstances of the utility's proposal. As discussed above, the Commission's decision-making in this case should be guided by a set of broader principles, including what amount and type of cost recovery is "just and reasonable," among other considerations.

Q. Have other state utility Commissions granted expense amortization methodologies that apply returns other than the utility's Weighted Average Cost of Capital (WACC)?

A. Yes. While there are likely numerous additional examples, the following table summarizes instances when other state Commissions approved various cost recovery mechanisms related to amortizing expenses. The outcomes include a blended rate, seven-year treasury rate and rate of return denial. In each case, costs are amortized using a return lower than the utility's WACC.

Table 3. Alternative Cost Recovery Examples

Year/Docket No.	**Utility**	**State**	**Permitted Return**
2017/UE 321	Idaho Power Company	OR	The Commission approved Idaho Power's request to continue return on deferred accounts during amortization consisting of a blended one, three, and five-year treasury rate, plus 100 basis points.[41]
2018/ E-7, Sub 819	Duke Energy Carolinas	NC	The Commission did not allow the utility's request for a return on the unamortized balance of costs reasonably incurred at the cancelled Lee Nuclear Project.[42]
2019/E-22, Sub 562, 566	Dominion Energy North Carolina	NC	The Commission did not allow the utility's request for a return on the unamortized balance of coal ash remediation costs.[43]
2022/ UE 408	Portland General Electric	OR	The Commission adopted a stipulation for recovery of wildfire and ice storm event expenses at a rate of return equal to the seven-year treasury rate, plus 100 basis points.[44]

[41] Idaho Power Company, *Application for Amortization,* February 28, 2017, p. 5; approved by Public Utility Commission of Oregon, Order no. 17120, March 21, 2017.
[42] State of North Carolina Utilities Commission, Docket No. E-2, Sub 819, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction,* January 24, 2018, p.163. Available at https://starw1.ncuc.gov/ncuc/ViewFile.aspx?NET2022&Id=80a5a760-f3e8-4c9a-a7a6-282d791f3f23. The Commission also noted on page 160 that in the cases of Duke Power Co., Docket No. E-7, Sub 338, 72 N.C.U.C. 173 (Nov. 1, 1982); Carolina Power & Light Co., Docket No. E-2, Sub 461, 73 N.C.U.C. 114 (Sept. 19, 1983); and Carolina Power & Light Co., Docket No. E-2, Sub 481, 74 N.C.U.C. 126 (Sept. 21, 1984), all involving abandoned nuclear plants, the Commission had refused to allow a return on certain unamortized expenditures.
[43] State of North Carolina Utilities Commission, Docket No. E-22, p. 132. The Commission also states, "the Commission determines that just and reasonable rates are achieved, based on the evidence in the record in this proceeding, only when the unamortized balance of CCR Costs are not allowed to earn a return" (p. 134).
[44] Public Utility Commission of Oregon, Order No. 22-435, November 3, 2022, p. 3.

Q. What are your conclusions from this research?

A. Commissions have exercised discretion in whether and how to apply returns when amortizing expenses. Based on the Table above and DEP's proposal, returns on deferred expenses may range from zero up to the utility's WACC.

IV. COST RECOVERY ALTERNATIVES AND IMPACT ON TOTAL COSTS

Q. What alternatives should the Commission consider as cost recovery options for CCR related expenses?

A. The Commission has discretion in how these costs should be recovered. First, as noted above, the Commission should consider partial or full disallowances of these costs. However, assuming the Commission moves forward with either a partial disallowance or full cost recovery, I present two alternatives to DEP's proposal to illustrate cost recovery options available to the Commission to reduce costs to customers related to coal ash basin closure at legacy plants (ARO costs): (1) expense (0% return) or (2) a return based on the seven-year treasury rate (3.87%).[45] Similarly, I present two alternatives for coal ash remediation costs related to active plants (non-ARO): (1) expense (0% return) or (2) a return based on the three-year treasury rate (4.23%). These respective treasury rates match the proposed amortization period for the expenditures. These examples are intended to represent a range of options, not all available alternatives. As I state above, I believe the Commission has discretion regarding how to treat deferred expense costs in this case.[46]

[45] Federal Reserve, *Market Yield on U.S Treasury Securities at 7-Year Constant Maturity,* https://fred.stlouisfed.org/series/DGS7.

[46] Please note that my calculations do not address the total revenue requirement needed to recover costs including taxes and working capital, as this is outside the scope of this testimony.

Q. Please explain your calculations for coal ash remediation costs related to legacy plants (ARO).

A. Using DEP's workpapers[47], I calculate the cost of DEP's proposal and my alternatives by adding the deferred coal ash recovery costs with the various proposed returns discussed above.. I then add the $29 million of previously disallowed costs that have been resubmitted, less insurance proceeds (net of legal fees), which results in the sum to be amortized. The calculation is shown below for DEP's proposal (regulatory asset).

Table 4. DEP Coal Ash Cost Recovery Proposal, ($ Thousands)[48]

Deferred ARO Environmental Costs	$	71,930
Return based on WACC	$	14,532
Resubmission of Previous Disallowances	$	29,258
Insurance Proceeds, net of legal fees	$	(8,884)
Balance for Amortization	**$**	**106,836**

DEP proposes to amortize these costs over seven years. I do not provide an opinion on this amortization period, but note that, if the Commission determines this is a reasonable period, the costs for amortization shown above and below can be divided by seven to calculate the annual revenue requirement that would be incorporated into rates, less any partial disallowances.

Q. Please provide the results of your ARO cost analysis.

A. The figure below shows the cost to be amortized based on the alternatives for recovery discussed above for legacy plants.

[47] Elliott Exhibit 4, SC4010-2 ARO Deferral (Supplemental).
[48] Elliott Exhibit 4, SC 4010-1 and SC4010-2.

Figure 1. Illustrative Cost Recovery Options for Coal Ash Removal
(Legacy Plants/ARO, $ Thousands, Nominal)

These results demonstrate that the rate of return authorized for CCR related expenditures has a significant ratepayer impact, around $14 million if regulatory asset treatment is granted for basins at legacy plants.

Q. Please explain your calculations for coal ash costs related to operational plants (non-ARO).

A. DEP's workpapers only calculate the three-year revenue requirement for the $28 million in costs incurred (South Carolina basis) from January 2019 to January 2021, assuming they are capitalized or are part of a regulatory asset.[49] I used this workpaper to estimate a total revenue requirement for these expenditures by leaving the estimated depreciation

[49] Based on a review of the Company's testimony and workpapers, it is not clear how they propose to address these costs.

expense constant after 2021, and extending this an additional 23 years to 2046, when costs for the initial expenditures would be fully recovered. This effectively represents an average depreciation schedule, as I do not model each proposed depreciation schedule separately. If these expenditures are capitalized, the actual revenue requirement will differ somewhat based on the fact that: (1) I do not know what returns will be approved by the Commission over this time period (I use carrying costs approved as of June 2019) and (2) the utility proposes to depreciate cost components on different schedules, ranging from 14 to 53 years. That said, the majority of costs will be recovered over 18 or 27 years,[50] so this estimate is a reasonable proxy of the total revenue requirement if the Commission chooses to capitalize the $28 million in past expenditures.[51]

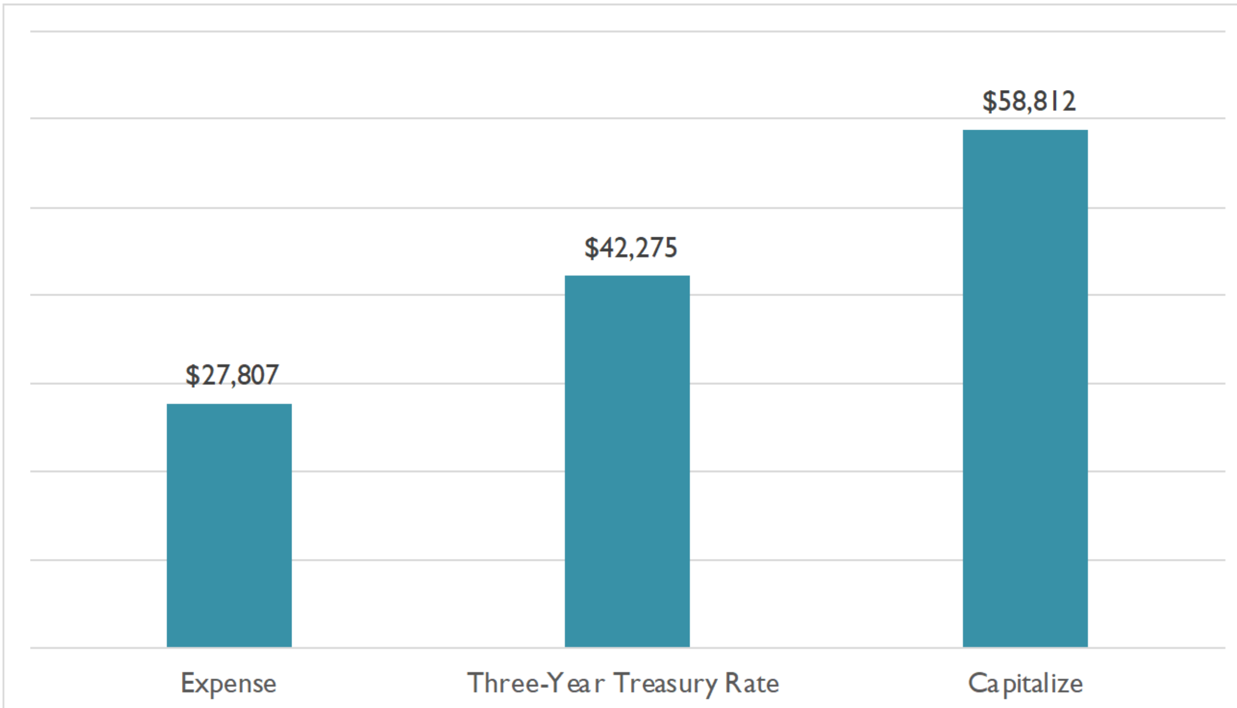
I calculate the ratepayer impacts of the various cost recovery options cited above by adding the deferred coal ash recovery costs with the applicable return (where applicable).

Q. Please provide the results of your non-ARO cost analysis.

A. The figure below shows the cost to be amortized based on the alternatives for recovery discussed above for CCR related expenditures at operational plants.

[50] Elliott Exhibit 4, SC5030-3, the first two depreciation groups represent 73 percent of total depreciation costs from January 2019 to March 2023.
[51] Elliott Exhibit 4, SC5030-3.

Figure 2. Illustrative Cost Recovery Options for Coal Ash Removal (Operational Plants/non-ARO, $ Thousands, Nominal)



These results demonstrate that the rate of return authorized for CCR related expenditures has a significant ratepayer impact, around $31 million (nominal dollars) in carrying costs under DEP's proposal for CCR related expenditures at operational plants.

Q. How do these findings relate to DEP's request for future regulatory asset treatment?

A. Future coal ash costs, if treated as a regulatory asset, would similarly accumulate depending on the level of costs incurred. Indeed, the carrying costs for regulatory asset treatment represent 20 percent of the total deferred environmental costs,[52] a substantial ratepayer burden that the Commission should weigh when deliberating how these costs, if

[52] $14,532 / $71,930 = 20%.

any, should be recovered. Over the depreciation lives assumed by DEP, I expect carrying costs will surpass the costs incurred from 2019-2021 at operational plants.

Q. Please summarize your findings and recommendations.

A. The Commission has discretion in how to treat coal ash remediation costs, the least costly of which is as an expense. The level of return granted for these expenditures has a significant, material impact on the total costs to ratepayers. I find the Commission should be guided by a set of fundamental principles, including whether costs and recovery mechanisms are "prudent" and "just and reasonable." As such, I believe that if the Commission grants partial or full cost recovery, the Company should not be granted a rate of return on its coal ash basin remediation costs.

Further, there is sufficient evidence based on historic environmental damages and health hazards posed by the coal ash facilities at issue here that partial or total cost disallowances should, at minimum, be considered.

I recommend the Commission weigh these factors when it considers how and if DEP should recover costs related to coal ash removal.

Q. Does this conclude your testimony?

A. Yes, it does.

Synapse
Energy Economics, Inc.

Eric Borden, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7042
eborden@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA*. Principal Associate,* May 2022 – Present

- Sponsors expert testimony and performs analyses related to utility electric vehicle incentives and policy, wildfire mitigation strategies and costs, risk modeling, rate design, cost allocation, and revenue requirement issues in General Rate Cases and Multi-year Rate Plans.
- Conducts research and analysis related to the cost-effectiveness of distributed energy resources and Integrated Resource Plans.
- Examines utility performance incentives and provides expertise on ratemaking issues.

The Utility Reform Network (TURN), San Francisco, CA*, Energy Policy Expert,* February 2015 - May 2022

- Prepared testimony, conducted analyses, drafted comments, and represented TURN in various proceedings at the California Public Utilities Commission (CPUC) related to general rate cases, wildfire-related safety applications, electric vehicle charging infrastructure, utility procurement, rate design, and demand response.

4 Thought Energy LLC, Chicago, IL. *Senior Energy Analyst*, June 2013 – January 2015

- Created financial models to forecast profits of potential site installations
- Researched state and regional public policy frameworks governing CHP
- Conducted analyses over electricity and natural gas price trends
- Developed presentations and marketing materials for investor meetings

International Renewable Energy Agency (IRENA) Bonn, Germany. *Consultant,* February 2014 – October 2014

- Hired to write a report on worldwide electricity sector battery storage, including primary applications for renewable energy integration, market developments, trends, and case studies
- Conduct research, review literature, interview key industry players, develop case study material
- Travel to Bonn, company sites, and research facilities
- Written report will be sent to policymakers in 167 IRENA member countries

Alexander von Humboldt Foundation (hosted by DIW Berlin), Berlin, Germany. *German Chancellor Fellow*, July 2012 – November 2013

- Research Project: "Energy Storage Technology and the Large-Scale Integration of Renewable Energy"
- Investigated the role of energy storage in Germany for renewable integration through literature review, interviews with German energy experts, and analysis comparing public policy support in Germany and the U.S. for storage technologies
- Invited to hold a presentation at the International Renewable Energy Storage Conference and Exhibition (IRES 2013)
- Discussions with German businesses and governmental ministries; special visit to European Union and NATO headquarters in Brussels
- Attended energy conferences and workshops in Berlin

The Kenrich Group, LLC, Chicago, IL. *Senior Consultant*, June 2008 – July 2009

- Consulted for multiple energy utilities in legal disputes with the Department of Energy (DOE)
- Performed detailed research and quantitative/qualitative analysis to analyze financial impact related to construction of coal-fired power plants, liquid natural gas facilities, and other types of construction
- Contributed to final reports and presentations submitted in arbitration, settlement, or court of law presenting KRG's expert opinion

Charles River Associates, Chicago, IL. *Associate - Intellectual Property*, July 2006 – May 2008

- Developed complex financial models including discounted cash flow, lost profit, and regression analyses to support expert reports within the context of intellectual property and financial litigation in multiple industries
- Created valuation models and supporting materials to value business entities
- Contributed to final reports and presentations submitted in arbitration, settlement, or court of law presenting CRA's expert opinion

EDUCATION

University of Texas, LBJ School of Public Affairs, Austin, Texas

Master of Public Affairs, specialization in Natural Resources and the Environment, 2012

Washington University, St. Louis, MO

B.S.B.A. Finance, Entrepreneurship, 2006

PUBLICATIONS

Battery Storage for Renewables: Market Status and Technology Outlook, International Renewable Energy Agency (IRENA), co-author with Ruud Kempener, 2015.

Germany's Energiewende, chapter 15 in Global Sustainable Communities Design Handbook, ed. Dr. Woodrow Clark, Elsevier Press, 2014.

Expert Views on the Role of Energy Storage for the German Energiewende, DIW Berlin and BMU "Stores" project, 2014.

Policy efforts for the development of storage technologies in the U.S. and Germany, DIW Discussion Paper, 2013.

Electric Vehicles and Public Charging Infrastructure: Impediments and Opportunities for Success in the United States, The University of Texas at Austin, 2012.

Clean Energy Technology and Public Policy, LBJ Journal of Public Affairs, editor and contributor, 2011.

TESTIMONY

A.21-06-021: Prepared Testimony Addressing Pacific Gas and Electric's Test Year 2023 General Rate Case – Wildfire Mitigation and New Customer Connections Cost Requests. June 13, 2022.

A.21-09-008: Prepared Testimony Addressing the Reasonableness of Pacific Gas and Electric 2020 Vegetation Management Balancing Account Overspend. May 25. 2022.

A.21-06-022: Prepared Testimony Addressing Pacific Gas and Electric's Framework for Substation Microgrid Solutions. March 30, 2022.

A.21-10-010: Prepared Testimony Addressing Pacific Gas and Electric's Electric Vehicle Charge 2 Proposal. March 2, 2022.

A.20-09-019: Prepared Testimony Addressing Pacific Gas and Electric's Wildfire Mitigation Memorandum Accounts. April 14, 2021.

A.19-08-013: Prepared Testimony Addressing Southern California Edison's Test Year 2021 Track 2 General Rate Case Memorandum Account Request – Wildfire Expenditures. September 4, 2020.

A.20-03-004: Joint Testimony with Eduyng Castano (SCE) Addressing Data Collection and Evaluation of the New Homes Battery Storage Pilot Program. September 1, 2020.

A.19-10-012: Prepared Testimony Addressing San Diego Gas and Electric's Power Your Drive 2 Electric Vehicle Charging Infrastructure Proposal. May 18, 2020.

A.19-08-013: Prepared Testimony Addressing Southern California Edison's General Rate Case Wildfire Management, Wildfire Risk, Vegetation Management, and New Service Connection Policy Issues and Cost Forecasts. May 5, 2020.

A.18-12-009: Prepared Testimony Addressing Pacific Gas and Electric's Enhanced Vegetation Management and System Hardening Wildfire Mitigation Expenditures. July 26, 2019.

A.18-09-002: Direct Testimony Addressing SCE's Grid Safety and Reliability Program Infrastructure Proposal. April 23, 2019.

A.18-06-015: Rebuttal Testimony Addressing SCE's Charge Ready 2 EV Infrastructure Proposal. December 21, 2018.

A.18-06-015: Direct Testimony Addressing SCE's Charge Ready 2 EV Infrastructure Proposal. November 20, 2018.

A.17-12-011: Direct Testimony Regarding Potential Effects of More "Cost Based" TOU Rates and Seasonal Differentiation of Tiered Rates. October 26, 2018.

A.18-02-016 et al.: Prepared Testimony Addressing Issues Pertaining to AB 2868 (Energy Storage). August 10, 2018.

A.17-12-002 et al.: Prepared Testimony Addressing the Proposal of SCE for Energy Storage Procurement. April 9, 2018.

A.17-01-020: Direct Testimony Addressing the Proposal of PG&E for a Fast Charging Infrastructure Program. July 25, 2017.

R.12-06-013: Direct Testimony Evaluating Hardship due to TOU Rates on Vulnerable Populations in Hot climate Zones. April 19, 2017.

A.15-09-001: Direct Testimony Addressing the Proposal of PG&E for Electric Distribution and New Business Expenditures. April 29, 2016.

A.15-02-009: Rebuttal Testimony Regarding PG&E's A.15-02-009 for EV Infrastructure and Education Program. December 21, 2015.

A.15-02-009: Direct Testimony Regarding PG&E's EV Infrastructure and Education Program. November 20, 2015.

A.14-11-003: Direct Testimony Addressing the Treatment of Solar Distributed Generation for Estimating Distribution System Capacity/Expansion Expenditures. May 15, 2015.

A.14-04-014/R.13-11-007: Testimony Regarding SDG&E's Application for Authority to Build Electric Vehicle Charging Infrastructure. April 13, 2015.

Resume updated July 2022