BEFORE THE
PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

APPLICATION OF
DUKE ENERGY CAROLINAS, LLC FOR INCREASE IN ELECTRIC RATES

DOCKET NO. 2023-388-E
DIRECT TESTIMONY OF
ERIC BORDEN

COAL ASH REMEDIATION, TARGETED UNDERGROUNDING, AND SELF-OPTIMIZING GRID ISSUES AND COST RECOVERY

SOUTH CAROLINA DEPARTMENT OF CONSUMER AFFAIRS

April 8, 2024

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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, and I have testified on undergrounding and grid modernization expenditures.

Since joining Synapse I have contributed to projects and testimony on regulated utility issues in California, Illinois, Maine, New Jersey, Wisconsin, New Hampshire, Maryland, New Mexico, Nova Scotia, Minnesota, and Alaska.

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

A. Yes. I testified in docket 2022-254-E on Duke Energy Progress' (DEP) coal ash remediation costs.

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 Carolinas' ("Duke", "DEC" 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 options for cost recovery related to "coal ash basin closure" for which the Company seeks regulatory asset treatment.[1] The Company refers to these costs as "asset retirement obligation" or "ARO" costs.[2]

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."[3] These costs appear to be similar to those incurred for coal ash basin closure, except they relate to operational coal plants. My analysis of environmental compliance cost recovery options related to basin closure and at operational plants is also relevant to the Company's request to treat coal ash basin compliance costs as a regulatory asset going forward. [4]

Lastly, I analyze two requests for cost recovery related to DEC's Grid Improvement Plan (GIP) – targeted undergrounding (TUG) and Self-Optimizing Grid (SOG).

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.

[1] Direct Testimony of LaWanda Jiggetts at 22:1-2 and Table on page 22.
[2] Id.
[3] Direct Testimony of LaWanda Jiggetts at 25:4-5.
[4] Direct Testimony of LaWanda Jiggetts at 38.

Q. If you do not directly address prudency related to coal ash expenditures, why is your testimony relevant?

A. Though I do not opine directly on whether all or a portion of DEC's coal ash remediation costs should be disallowed, I present information that is directly relevant to the Commission's decision on this issue as it considers the level of cost recovery appropriate for these expenditures related to both past and ongoing deferral treatment, as well as issues related to reasonableness of coal ash remediation.

Q. Why didn't you recommend a specific disallowance amount, if you found sufficient evidence for the Commission to consider partial or full disallowances?

A. The goal of my testimony is to outline alternative options for the Commission in addressing CCR remediation costs. Partial or total disallowance are only two of the options available to the Commission. To calculate a specific disallowance number requires extensive analysis that was beyond the scope of my engagement with the Department. Further, the Commission's decision will be based on the whole record, including but not limited to my testimony. I expect that additional facts, evidence, and analysis presented in hearings and summarized in briefing will illuminate the degree to which Duke's actions were imprudent, and the level of disallowances that must be levied to ensure just and reasonable rates.

Q. Please summarize your findings related to coal ash expenditures and cost recovery.

A. I find the following:

1. Given the toxic constituents in coal ash, the Company's admitted violations of the law and subsequent enforcement actions, and the Company's inability to keep CCR out of contact with surrounding water bodies, the Company has created potential health and

environmental hazards from its coal ash basins for which it now seeks cost recovery for 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. DEC has not adequately supported its proposal to recover legacy coal ash remediation costs (ARO) as part of a regulatory asset.

4. DEC has not adequately supported its proposal to capitalize coal ash remediation costs (non-ARO) at active plants and earn a return on the deferral amount.

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 $57 million in carrying costs to the incurred costs for these activities.[5]

7. Capitalization of coal ash remediation plus deferral returns at WACC for remediation costs at active plants (non-ARO) adds around $37 million in carrying cost from 2019–2024.[6]

8. Capitalization and return on non-ARO deferral costs, over the full 20-year depreciation life, would result in collection of approximately $276 million in carrying costs in addition to the $69 million in incurred direct costs.

Q. Please summarize your findings related to targeted undergrounding and Self-Optimizing Grid expenditures.

A. I find the following:

[5] DEC ORS First AIR 1-7 Supplemental Attachments, Excel workpapers SC4010(A).
[6] DEC ORS First AIR 1-7 Supplemental Attachments, Excel workpapers SC5030(A).

1. TUG expenditures of $42 million from 2019–2023 were not reasonably incurred as undergrounding was not demonstrated to be the most cost-effective or best approach to improve reliability for poor-performing circuits.
2. The Company's cost-benefit analyses for TUG used generic or average unit costs which is inappropriate for undergrounding projects.
3. SOG expenditures are not cost-effective for residential ratepayers and disproportionately benefit commercial and industrial customers.

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.
4. The Commission should deny returns on coal-ash-related remediation costs going forward.
5. The Commission should deny cost recovery of $42 million for TUG expenditures.
6. The Commission should allocate costs for the SOG program in proportion to benefits of the program: 5 percent to the residential class, 95 percent to the commercial and industrial classes.

II. COAL ASH REMEDIATION COSTS

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

A. DEC seeks to recover CCR removal expenditures related to coal ash basin closure at "legacy sites" (ARO) as well as coal ash environmental compliance costs at active plants (non-ARO). DEC seeks regulatory asset treatment for $238 million of ARO costs on a South Carolina basis; DEC requests an additional $57 million to this incurred amount due to carrying costs.[7] The Company also requests previously disallowed costs for recovery; it does not propose that these be included in the regulatory asset.

Table 1. Costs by plant requested by DEC ($ million, South Carolina retail basis)

	Retail	Previously Disallowed	Total Costs
Allen	$ 28	$ -	$ 28
Belews Creek	$ 33	$ -	$ 33
Buck	$ 57	$ 9	$ 66
Cliffside	$ 30	$ -	$ 30
Dan River	$ 18	$ 27	$ 45
Marshall	$ 48	$ -	$ 48
W.S. Lee	$ 21	$ -	$ 21
Total	**$ 235**	**$ 36**	**$ 271**

Source: Direct testimony of Jessica Bednarcik at 80.

The Company proposes to capitalize $67 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 ($52 million): $15 million in depreciation expense, $28 million due to capitalized treatment in the historical period, and another $9 million for return due to regulatory asset treatment at the WACC.[8] The remainder of these costs, constituting

[7] Direct Testimony of LaWanda Jiggetts at 22:15.
[8] DEC ORS First AIR 1-7 Supplemental Attachments, Attachment SC5030(A).

around $52 million of net plant,[9] plus carrying costs of $238 over the full depreciation life will presumably be part of a future request.

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

Table 2. Coal ash remediation costs ($ thousands, South Carolina basis)

Legacy Sites (ARO)	$ 294,773
Resubmission (Previously Disallowed)	$ 35,954
Active Plants (Non-ARO)	$ 52,033
Insurance Proceeds, net of legal fees	$ (46,594)
Total	$ 336,166

Source: DEC ORS First AIR 1-7 Supplemental Attachments, Excel workpapers SC4010(A); SC5030(A).

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

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

A. Yes. DEC 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. How are the remaining sections of your testimony organized?

A. The remaining sections of my testimony discuss why there is sufficient publicly available evidence that the Commission should consider disallowances of coal ash remediation

[9] DEC ORS First AIR 1-7 Supplemental Attachments, Attachment SC5030(A). South Carolina basis.
[10] *DEC ORS First AIR 1-7 Supplemental Attachments, Excel workpapers SC4010(A); SC5030(A).*
[11] Direct Testimony of LaWanda Jiggetts at page 37:19-21.

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. I then analyze, discuss, and recommend changes to the Company's requests for TUG and SOG investments.

A. THE COMMISSION SHOULD CONSIDER A PARTIAL OR TOTAL DISALLOWANCE OF COAL ASH REMOVAL COSTS DUE TO COMPANY ACTIONS RELATED TO STORAGE OF COAL ASH

Q. What argument does Duke make in support of its full recovery of costs, plus a rate of return?

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 DEC'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 5.

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.

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

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[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.

A. This appears to be the case, as all of the subject coal ash ponds 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] As stated by the South Carolina Supreme Court, "it was known from at least the late 1970s that CCR wastewater presented a serious potential source of surface and groundwater contamination and that the wastewater could cause extensive environmental damage if not properly handled. Likewise the risks CCRs posed to human health were well documented."[18]

The potential danger presented by these coal ash basins was so great that the North Carolina Department of Environmental Quality required Duke in 2016 to provide households within one-half mile of all of the coal-fired power plants with coal ash basins at issue here with bottled drinking water.[19] In 2016, North Carolina passed an amendment to the 2014 *Coal Ash Management Act* that required Duke to supply permanent clean water solutions to affected households due to potential contamination of drinking water.[20]

[15] Direct Testimony of Jessica Bednarcik at 9.
[16] Environmental Protection Agency (EPA), https://www.epa.gov/coalash/coal-ash-basics.
[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] *Duke Energy Carolinas, LLC v. S.C. Office of Regulatory Staff*, 434 S.C. 392, 398 (2021)
[19] 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
[20] 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

Duke also offered households a financial payout if residents were willing to release Duke from future liability.[21]

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. Most notable is the Dan River coal ash spill which released around 39,000 tons of ash and 27 million gallons of ash pond water into the Dan River.[22] Duke plead guilty and apologized to several violations of the law, stating "We are accountable for the spill and its aftermath and take responsibility for all of the violations contained in the plea agreement."[23] The Company admitted to several failures of coal ash management related to the Dan River spill and at other plants, including but not limited to: not acting on the advice of multiple external consultant reports and internal engineers regarding potential safety hazards, record-keeping and information-sharing failures, denying relatively low-cost measures like camera inspections to ensure safety despite multiple requests from internal staff, and others.[24]

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[21] 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/

[22] U.S. Department of the Interior, https://www.cerc.usgs.gov/orda_docs/CaseDetails?ID=984.

[23] Corporate Crime Reporter, *Duke Energy Apologizes for Environmental Crimes, Will pay $102 million,* March 2015, https://www.corporatecrimereporter.com/news/200/duke-energy-apologizes-for-environmental-crimes/.

[24] Joint Factual Statement at 12-31, *United States v. Duke Energy Business Services LLC, et al* (EDNC 2015); https://www.justice.gov/usao-ednc/file/771581/dl

The Company also entered plea or settlement agreements related to alleged violations that occurred at the Allen, Belews Creek, Buck, Cliffside, Lee, and Marshall plant coal ash storage sites, all of which request cost recovery for coal ash remediation in this case.[25]

As shown in Table 3 below, research conducted by EarthJustice and the Environmental Integrity Project found each site contains contaminants above safe levels. According to the report, the Allen plant ranks as the fifth most contaminated site in the United States.

Table 3. Coal ash pollutants at plants sought for cost recovery

Plant	**Pollutants above safe level**
Allen	Arsenic (x7), Beryllium (x6), Boron (x1), Cadmium (x1), Cobalt (x466), Lithium (x12), Selenium (x5), Thallium (x1)
Belews Creek	Arsenic (x5), Beryllium (x1), Boron (x7), Cobalt (x40), Lithium (x24), Molybdenum (x8), Radium 226+228 (x1)
Buck	Boron (x1), Cobalt (x12), Lithium (x7), Molybdenum (x1), Sulfate (x1)
Cliffside	Arsenic (x9), Beryllium (x2), Boron (x1), Cobalt (x38), Radium 226+228 (x1), Selenium (x1), Sulfate (x1), Thallium (x1)
Dan River	Arsenic (x3), Cobalt (x1), Lithium (x3)
Marshall	Arsenic (x5), Barium (x1), Beryllium (x1), Boron (x5), Cobalt (x22), Lithium (x2), Radium 226+228 (x2), Thallium (x1)
W.S. Lee	Arsenic (x2), Beryllium (x1), Boron (x1), Cobalt (x15), Lithium (x2), Molybdenum (x4), Radium 226+228 (x1)

Source: EarthJustice, Environmental Integrity Report, Poisonous Coverup: The Widespread Failure of the Power Industry to Clean Up Coal Ash Dumps, Table A4, Rank 5, 45, 143, 77, 201, 98, 131 (in order as shown in the table).

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

[25] Consent Agreement, *In Re: Duke Energy Carolinas, LLC W.S. Lee Steam Station* (2014) (14-13-HW); North Carolina Consent Agreements (2020), https://files.nc.gov/ncdeq/Coal%20Ash/2020-closure/2020-02-05---Consent-Order---file-stamped.pdf.

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

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

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

A. Company witness Riley states that there is a time value of money incurred by utilities, "regardless of whether the underlying costs are capital or without the deferral would have been operating expenses in nature."[26] The Company admits it "did not consider proposing any other recovery mechanisms for purposes of this case"[27].

Q. What is your response to these arguments?

A. The proposed treatment of costs has not been demonstrated to be in the best interest of ratepayers.

[26] Direct testimony of Sean Riley at 6:11-16.
[27] Data request SCDCA 3-1(c).

First, the expenditures are akin to O&M which under traditional utility accounting do not earn a return, certainly not at the Company WACC, even for deferral amounts.

Second, while I do not disagree that there may be a "time value of money" associated with past expenditures that are not recovered concurrently, the Commission must incorporate into its decision-making the problematic nature of the Company's history with coal ash, discussed above, for which the Company has admitted guilt. It would seem to add insult to injury to allow profits, or even any "time value of money," for activities intimately connected to illegal behavior by the Company, and then ask ratepayers to foot the bill.

Third, the Commission should consider intergenerational equity. Most of the costs to properly dispose of coal ash come primarily due to previous decades of coal plant operation. Duke requests the current generation of ratepayers to absorb costs from this historical activity.

Fourth, the Commission should consider affordability. The Company's proposal is the most costly approach to recover these costs over time. As demonstrated below, adding proposed returns to the remediation costs requested for recovery significantly increases ratepayer burden.

Lastly, it is the utility's burden to demonstrate that these returns are necessary and in the ratepayer interest. It has not done so. If approval and collection of these costs more quickly is meant to alleviate the Company's regulatory lag concerns (i.e. the period of time between when costs are incurred and costs are recovered), the Company could have filed a rate case sooner, or used another regulatory vehicle to request recovery closer to the time of the expenditures. This principle also applies to the Company's request for future regulatory asset treatment. More frequent reasonableness reviews of these costs would be preferable, from an affordability standpoint, than accrual of utility carrying costs during periods between rate cases.[28]

Q. Is it appropriate for Duke to capitalize non-ARO coal ash remediation costs and earn a return at WACC on the deferral amount?

A. No. These costs are not traditional capital expenditures. Capital expenditures represent the "net amount of investment in the utility's plants and other assets that are committed to rendering electricity service to customers, i.e., they are used and useful."[29] 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 O&M expenses, which must be incurred to reliably operate utility system equipment (in this case, the power plant) but do not represent "used and useful" plant itself. Additional return on these expenditures should not be allowed as well (see above).

The Commission has flexibility with regard to how coal ash remediation costs may be recovered from ratepayers and is not limited to regulatory asset treatment with returns at Company WACC or capitalization, as the Company's testimony seems to imply. The

[28] *Duke Energy Carolinas, LLC v. S.C. Office of Regulatory Staff*, 434 S.C. 392, 428 (2021) ("The PSC concluded that to rule in favor of Duke's position would encourage the utility to seek more accounting deferrals in the future, which would 'greatly inflate costs in future years, which w[ould] be passed on to customers through rates.'" (quoting Docket No. 2018-318-E, Order No. 2019-341 at 97)).
[29] *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).
NARUC, *A Comprehensive Survey of Coal Ash Law and Commercialization,* January 2020, https://pubs.naruc.org/pub/A6923B2D-155D-0A36-31AA-045B741819EC, p. 83.

Commission in South Carolina, as well as other jurisdictions, have recognized this, as discussed further in the ensuing section.

C. 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.[30]

The Commission has also stated, and the South Carolina Supreme Court affirmed, that in accordance with Hope:

> Treatment of deferrals is ultimately a matter of the [PSC's] discretion. The [PSC] has a duty to balance the needs of the public and the utility such that the public is served without the utility being disserved. This approach [denying carrying costs in the initial order] represents exactly such a balance.[31]

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 costs at issue and proposal. As discussed above, the Commission's decision-making in

[30] Docket No. 2018-318-E, Order No. 2019-454, October 18, 2019, at 15.
[31] *Duke Energy Carolinas, LLC v. S.C. Office of Regulatory Staff*, 434 S.C. 392, 430 (2021) (quoting Docket No. 2018-318-E, Order No. 2019-341 at 96) (brackets in original).

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 deferral expense methodologies that apply returns other than the utility's 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, a return lower than the utility's WACC was applied.

Table 4. Alternative cost recovery examples

Year/Docket No.	Utility	State	Return Permitted
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.[32]
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.[33]
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.[34]
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.[35]

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 DEC's proposal, returns on deferred expenses may range from zero up to the utility's WACC.

[32] Idaho Power Company, *Application for Amortization,* February 28, 2017, p. 5; approved by Public Utility Commission of Oregon, Order no. 17120, March 21, 2017.

[33] 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.

[34] 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).

[35] Public Utility Commission of Oregon, Order No. 22-435, November 3, 2022, p. 3.

D. 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. If, however, the Commission moves forward with either a partial disallowance or full cost recovery, I present two alternatives to DEC'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 five-year historical weighted average treasury rate (2.27%).[36] Similarly, I present two alternatives for coal ash remediation costs related to active plants: (1) (non-ARO): expense (0% return) or (2) a return based on the five-year historical weighted average treasury rate (2.16%). These respective treasury rates approximate the time period over which costs have been incurred (2019-2023). 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.[37]

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

A. I calculate the cost of the various cost recovery options cited above by adding the deferred coal ash recovery costs with the required return based on the percentages shown above.

[36] Federal Reserve, *Market Yield on U.S Treasury Securities at 5-Year Constant Maturity,* https://fred.stlouisfed.org/series/DGS5 .

[37] Please note 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.

DEC proposes to amortize ARO 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 analysis.

A. The table below shows the cost to be amortized based on the alternatives for recovery discussed above for legacy plants (ARO).

Table 5. Illustrative cost recovery options for coal ash removal (legacy plants/ARO, $ thousands, nominal)

	DEC Proposal	Weighted Average Treasury Yield	No Return
Expenses	$238,185	$238,185	$238,185
Return	$56,588	$37,075	$0
Total Deferral	$294,773	$275,260	$238,185

Source: Calculated from DEC ORS First AIR 1-7 Supplemental Attachments, Excel workpapers SC4010(A).

These results demonstrate that the rate of return authorized for CCR-related expenditures has a significant ratepayer impact, around $57 million if the return is accepted as proposed compared to no return being permitted.

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

A. DEC's workpapers only calculate the approximately five-year revenue requirement for the $67 million in costs incurred (South Carolina basis) from January 2019 to June 2022, assuming they are capitalized and earn additional return on the deferral period. I used this workpaper to estimate a total revenue requirement for these expenditures by leaving the estimated depreciation expense constant, and extending this an additional 17 years to 2041, 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. The actual revenue requirement if these expenditures are capitalized 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 assume carrying costs approved as of June 2019) and (2) the Company proposes to depreciate cost components on different schedules, ranging from 11 to 35 years. That said, the weighted average service life of the depreciation groups is 20.3 years, so this estimate represents a reasonable proxy of the total revenue requirement if the Commission chooses to capitalize and provide an additional return on the regulatory asset for the $67 million in past expenditures.[38]

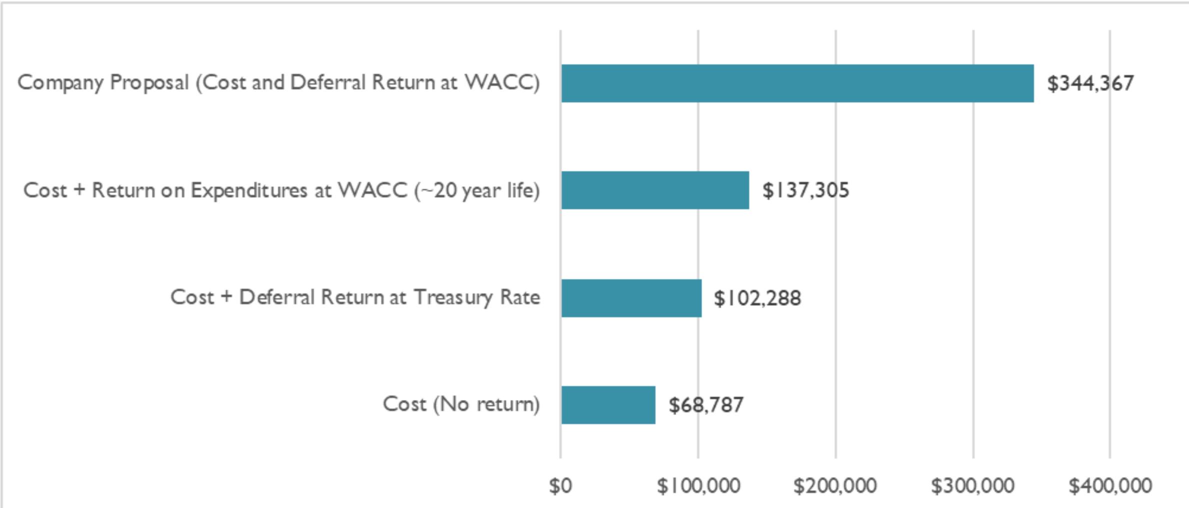
I calculate the ratepayer impacts of the various cost recovery options cited above by adding the deferred coal ash recovery costs with the applicable return (where applicable).

Q. Please provide the results of your analysis.

A. Figure 1 below shows the cost to be amortized based on the alternatives, for the recovery of CCR-related expenditures at operational plants (non-ARO).

[38] DEC ORS First AIR 1-7 Supplemental Attachments, Excel workpapers SC5030(A).

Figure 1. 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, up to $276 million (nominal dollars) for CCR-related expenditures at operational plants if no returns are allowed.

Q. How do these findings relate to DEC's request for future regulatory asset treatment of ARO CCR costs?

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 24 percent of the total deferred environmental costs,[39] a substantial burden that the Commission should weigh when deliberating how these costs, if any, should be recovered. Over the depreciation lives assumed by DEC, I expect carrying costs will surpass the costs incurred from 2019–2024 at operational plants.

Q. Please summarize your findings and recommendations.

[39] $56,588 / $238,185= 24%.

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, if partial or full cost recovery is granted, the Company should not be granted a rate of return on its costs.

Further, there is sufficient evidence based on historical 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 DEC should recover costs related to coal ash removal.

If Duke is allowed to recover any ARO-related costs, I recommend no return be allowed for the deferral period. If any non-ARO costs are allowed cost recovery, I recommend they be treated as O&M expenses and allowed no return.

III. TARGETED UNDERGROUNDING

Q. What is the purpose of the Company's TUG program?

A. The Company states the purpose of its TUG is to provide reliability and resiliency "during major events such as severe storms to minimize the number of outages and restore service more quickly and cost effectively to all customers in South Carolina."[40] To achieve this, the Company converted 25 miles of overhead line underground.[41]

Q. How did the Company select circuits for undergrounding?

A. The Company states that it uses a range of criteria to select it projects, including reliability statistics, age of assets, location, and vegetation impacts.[42] In particular, the Company ranked areas of its service territory by outage events per mile for each target segment, and then grouped these ranked segments geographically.[43] To make the final list of projects, connected areas/segments must all be within the top 1/3 of non-major event day (MED) events per mile, for which thresholds were set by region of the service territory.[44] The Company then conducted a cost-benefit analysis (CBA), comparing the cost of the project to the reliability benefits. Once the Company completed the CBA, projects with a positive net present value (NPV), which is indicative of a positive benefit-to-cost ratio (BCR),[45] that met other reliability criteria were selected, reviewed, and sent for approval by TUG Leadership.[46]

Q. What did the undergrounding cost-benefit analysis entail?

[40] Direct testimony of Brent Guyton at 19-20.
[41] Direct testimony of Brent Guyton at 19.
[42] Direct testimony of Brent Guyton at 20.
[43] Confidential attachment to ORS 5-51, "TUG Detail Planning Application Guide," at 10 (Figure 4) and 12.
[44] Confidential attachment to ORS 5-51, "TUG Detail Planning Application Guide," at 14.
[45] A BCR divides the NPV costs by benefits. If benefits are greater than costs, it will result in a BCR that is greater than one.
[46] Confidential attachment to ORS 5-51, "TUG Detail Planning Application Guide," at 20.

A. Costs for each project were compared with reliability benefits including avoided outages and momentary interruptions, as well as avoided asset management and vegetation management costs.[47]

Q. How much did the Company spend on its TUG program?

From 2019–2023, the Company spent a total of $42.3 million to underground 25 miles of overhead power lines, as shown in the table below. This equates to $1.7 million per mile.

Table 6. Annual TUG expenditures

	2019	**2020**	**2021**	**2022**	**2023**	**Total**
Targeted Undergrounding	$ 6,282,072	$ 5,388,531	$ 7,398,655	$ 11,140,760	$ 12,082,786	$ 42,292,804

Source: DR ORS 5, attachment "DEC ORS DR 5 Actual Costs 2019-2023."

Q. Do you have concerns about the TUG program?

A. Yes, I have two primary concerns related to the Company's CBA, which informs whether a TUG project is pursued or not. I summarize these concerns below and explain them in more detail in the following sections.

First, the Company's CBA considers the cost-effectiveness of only one mitigation—undergrounding—rather than assessing the cost-effectiveness of multiple alternatives. This is inappropriate and insufficient to demonstrate reasonableness because undergrounding is likely the most expensive remediation available (see, e.g., Figure 2) to the utility to improve reliability and resiliency issues. Without assessing the cost-effectiveness of multiple alternatives, it is impossible to conclude that the selected

[47] Conf DEC ORS 10-19, attachments.

undergrounding projects provided the best ratepayer value for the cost compared with available alternatives.

Second, DEC uses a Company average unit cost for undergrounding projects in its CBA, rather than project-specific costs. Since undergrounding costs can vary significantly by project, the utility should have used more accurate project-specific estimates to determine cost-effectiveness for undergrounding. This is evidenced in the Company's statement that it incurred higher unit costs than anticipated, [48] resulting in lower BCRs than expected.

A. THE COMPANY FAILED TO ASSESS ALTERNATIVES TO UNDERGROUNDING

Q. Did DEC assess alternatives to undergrounding in its cost-effectiveness analysis?

A. No. The Company states it did not perform an alternative analysis to undergrounding.[49] The Company's CBAs provided in discovery confirm that only the cost-effectiveness of undergrounding was examined.[50]

Q. Why is it problematic that the Company did not assess alternatives to undergrounding?

A. Simply showing that the reliability benefits of undergrounding exceed the costs[51] does not make undergrounding the most cost-effective or reasonable option to pursue for attaining greater reliability on poor-performing circuits. There are numerous alternatives to undergrounding such as: vegetation management; equipment maintenance and repair (including but not limited to pole replacement, transformer replacement, conductor

[48] Direct testimony of Brent Guyton at 23.
[49] DR DCA2-35.
[50] DR ORS 10-19, attachments.
[51] I note that several of the Company's CBA results show benefits that are less than costs incurred. It is not clear whether or not DEC pursued these projects. See, for example, ORS DR 10-19,

replacement, etc.); installation of steel poles or covered conductor (thicker, insulated wire that can withstand vegetation contact);[52] and others. All of these options tend to be less costly than undergrounding. Even if these alternatives do not provide the same level of reliability benefits as undergrounding, alternatives should be considered to undergrounding because they might prove more cost-effective or reasonable to pursue for a given circuit or area.

Q. Can you provide an example of how a program that provides lower reliability benefits compared with undergrounding can still be more cost-effective?

A. Yes. Below I provide an illustrative example using unit cost values that are close to those modeled in DEC's analyses. In this illustrative example, undergrounding is compared with conductor replacement for a 0.5 mile segment of overhead conductor. Both undergrounding and conductor replacement result in a positive BCR. Although conductor replacement results in benefits that are 60 percent less than undergrounding, it is more cost-effective from a BCR perspective.

Table 7. Illustrative benefit-cost analysis

Alternative	Cost per Mile	Total Cost	Reliability Benefits	Benefit-Cost Ratio
Conductor Replacement	$ 370,000	$ 185,000	$ 400,000	2.16
Undergrounding	$ 1,740,000	$ 870,000	$ 1,000,000	1.15

Q. Is this example realistic?

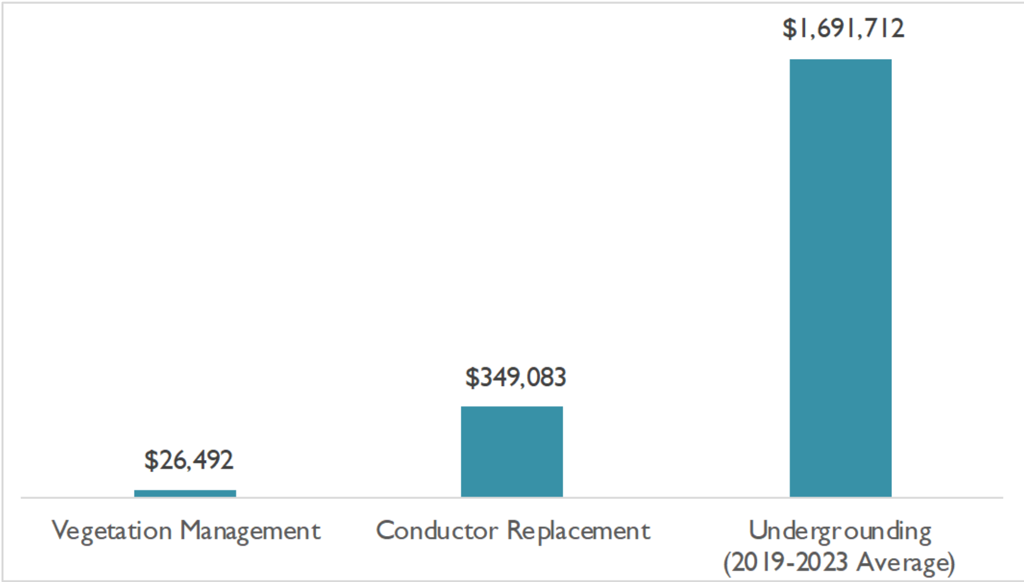
[52] Sometimes this is referred to as "tree wire." For more information see Southern California Edison, *Covered Conductor – Everything You Need to Know (Compendium),* https://www.sce.com/sites/default/files/AEM/Supporting%20Documents/2023-2025/Covered%20Conductor%20Compendium.pdf.

A. I believe that it is. The costs of conductor replacement and vegetation management are significantly lower than undergrounding. Indeed, undergrounding is *385 percent more* expensive on a per mile basis than conductor replacement, based on average costs for these activities.[53] Therefore, the benefits associated with alternatives to undergrounding need only be a fraction of undergrounding when, as is often the case, costs are significantly lower.

Moreover, implementing lower-cost alternatives can also allow for a greater number of projects to be undertaken. Thus, for the same budget, a greater number of cost-effective projects could be implemented, which would enable more customers to benefit from the reliability investments. Alternatively, less ratepayer money could be spent while still allowing for reliability improvements.

[53] I note that the unit cost comparison for vegetation management is less straightforward as this would need to be accomplished more than once to achieve reliability benefits above and beyond routine operations. If accomplished every year for 30 years (the assumed lifespan of undergrounding) the present value of these costs is about $344,000 (see Figure below), assuming a discount rate of 6.55 percent, the utility WACC utilized by the utility in its CBAs. Conductor replacement costs from DR ORS 10-19, attachment "Conf DEC ORS DR 10-19 TUG CBA Wave 5," tab "lookups;" Undergrounding in nominal dollars from DR ORS 5, attachment "DEC ORS DR 5 Actual Costs 2019-2023." Total cost from this DR divided by 25 miles (see witness Guyton at 19) for average cost of $1.7 million per mile.

Figure 2. Cost per overhead mile of undergrounding vs. select alternative mitigations



Source: These unit costs were readily available in utility workpapers; I believe other mitigations such as pole replacement or other equipment like transformers would also compare favorably to undergrounding. From DR ORS 10-19, attachment "Conf DEC ORS DR 10-19 TUG CBA Wave 5," tab "lookups;" Undergrounding in nominal dollars from DR ORS 5, attachment "DEC ORS DR 5 Actual Costs 2019-2023." Total cost from this DR divided by 25 miles (see witness Guyton at 19).

Q. Did you conduct a CBA of available alternatives and compare this to undergrounding?

A. No. At this time, I do not have sufficient information from the utility to perform this analysis.[54] Further, this analysis should have been conducted by DEC (a) before it moved forward with its undergrounding projects and (b) to justify the reasonableness of its expenditures, as the ultimate burden of demonstrating reasonableness is on the utility.

[54] For example, I do not have data on the reduction in faults due to conductor replacement or other alternatives. Further, more accurate CBAs would integrate project-specific costs for undergrounding, as well as alternatives, which is also information that was not provided by DEC to the best of my knowledge. However, this data was requested in DCA's 4th discovery request and may be incorporated into supplemental or surrebuttal testimony.

B. THE COMPANY DID NOT USE PROJECT-SPECIFIC UNIT COSTS TO ASSESS THE COST-EFFECTIVENESS OF UNDERGROUNDING

Q. What unit costs did the Company use in its CBA assessing undergrounding?

A. The Company used generic, or non-project-specific unit costs. Many projects assumed a cost of $850,000 per mile, while others assumed $1.7 million per mile.[55] The Company's workpapers indicates these are estimated or average costs (based on multiple projects).[56]

Q. Is it appropriate to utilize average or generic unit costs for undergrounding projects?

A. No, particularly because the Company used the CBA as a primary screening tool for whether to pursue undergrounding. Generic cost estimates should have been updated based on more detailed engineering reviews of project scope before final project selection.

This is especially the case for undergrounding, in contrast to other types of utility investments or programs because the cost of undergrounding is highly project-specific. For example, Southern California Edison estimates there is a 375 percent unit cost difference between a "high" difficulty undergrounding project and "low" difficulty project.[57] This large discrepancy in specific project costs makes the use of average or generically assessed costs inappropriate to properly assess undergrounding.

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[55] DR ORS 10-19, attachments.

[56] DR ORS 10-19, attachment "Conf DEC ORS DR 10-19 TUG_Spartan," Tab "Area Data – 2019-2021 Plan," states "Initial year costs estimates at $850K/mile on average for full portfolio in initial year 2019. As program scales, program efficiencies due to scaling and proficiency with new processes will deliver cost/mile improvements that are estimated to result in $750K/mile on average for 2020 and $725K/mile for 2021." Attachment "TUG CBA Wave 5" tab "Lookups" states the $1.7 million cost is a "used average for DEC/DEP."

[57] "Low" difficulty projects are expected to cost around $1.2 million per mile, while "high" difficulty projects are expected to cost around $4.5 million per mile. See A.23-05-010, SCE-04, Vol. 5, Part 2 Workpaper, p. 26.

Q. Could the use of generic cost estimates lead to overestimates of project cost-effectiveness?

A. Yes. The Company admits actual costs exceeded the utility's assumptions in its CBAs: "The TUG program actual cost per mile has been higher than the original assumptions."[58] CBAs used to justify projects have therefore likely decreased from when they were screened by DEC, assuming benefits have not changed. I do not know yet whether, or by how much, CBAs were overstated and have requested additional data on this issue through discovery.[59]

IV. SELF-OPTIMIZING GRID

Q. Please describe DEC's SOG expenditures.

A. The Company's SOG project consists of multiple areas of investment, including an advanced distribution management system (ADMS), segmentation and automation, capacity and connectivity, and substation bank capacity.[60] The Company describes its SOG expenditures as providing reliability benefits through automated devices on the distribution system. Specifically, the Company claims investments allow it to "automatically reroute power around trouble areas, like a tree on a power line, to quickly restore power to the maximum number of customers and rapidly dispatch line crews directly to the source of the outage."[61]

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[58] Direct testimony of Brent Guyton at 23.
[59] DR DCA 3-1 and 4-1.
[60] Fogg Direct Exhibit 1, p. 7.
[61] Direct testimony of Brent Guyton at 14.

Although the primary purpose of these expenditures is greater reliability, the Company also notes several "trends" that require SOG and other GIP investments including load growth, storm activity, distributed energy resources (DERs), and others.[62] To date, the Company has spent $71.5 million on these initiatives on a South Carolina basis.[63]

Q. Has the Company provided a CBA to justify its expenditures?

A. Yes. The Companies' CBA quantifies overall costs and benefits of SOG, finding that reliability benefits exceed costs with a BCR of 8.6. Reliability benefits of expenditures comprise 97 percent of total benefits on a present value basis.[64]

Q. Do you have any concerns with how DEC has justified its SOG expenditures?

A. Yes. First, SOG consists of multiple types of projects with different types of benefits. DEC has presented no information, to my knowledge, regarding which projects it has pursued for which it requests cost recovery here, nor has it demonstrated that the project or group of projects were necessary. For example, the utility could have shown power flow on a circuit with insufficient capacity to accommodate DERs, which the utility had to upgrade. Instead, the utility has lumped together multiple types of investment in its cost request. While the utility presents a more general CBA related to a full rollout of the SOG program, it does not provide a CBA to justify the expenditures under review in this rate case. Put another way, it is not clear whether the benefits of the expenditures at issue in this docket exceeded the costs, and if they did not, why they should be recovered from ratepayers.

[62] Direct testimony of Brent Guyton at 23.
[63] Direct testimony of Brent Guyton at 18.
[64] DR ORS 5-13(h), attachment "Conf DEC ORS DR 5-13(h)."

Q. Based on these flaws, what is your recommendation?

A. While I do not recommend a disallowance based solely on these shortcomings, the Company should present more cost-effectiveness information specific to the costs for which it seeks recovery, rather than for the SOG program as a whole. If it cannot demonstrate their reasonableness to the Commission, they should be disallowed.

Q. Does the CBA provide any other important insights related to the reasonableness of these expenditures?

A. Yes. The Company's CBA indicates that the program's costs are expected to significantly exceed the benefits for residential ratepayers, because benefits predominately go to commercial customers, who have much higher value of lost load (VOLL) than residential customers. The following tables show the Company's assumptions by class, which it has adapted from studies by Lawrence Berkeley National Laboratory (LBNL).

Table 8. Value of lost load assumptions by customer class

Momentary Interruptions (Cost per Event)	**2023**	**2024**	**2025**	**2026**	**2027**
Large C&I	$6,519.48	$6,682.46	$6,849.53	$7,020.76	$7,196.28
Small C&I	$578.03	$592.48	$607.30	$ 622.48	$ 638.04
Residential	$6.40	$6.56	$6.72	$6.89	$7.06

Reduced Outages (Non Major Events, Cost per Event)	**2023**	**2024**	**2025**	**2026**	**2027**
Large C&I	$20,258.69	$20,765.16	$21,284.28	$21,816.39	$22,361.80
Small C&I	$2,534.88	$2,598.26	$2,663.21	$2,729.79	$2,798.04
Residential	$13.08	$13.40	$13.74	$ 14.08	$14.43

Source: These values appear in the utility workpapers: DR ORS 5-13(h), attachment "Conf DEC ORS DR 5-13(h)," but cite to publicly available information at LBNL, https://emp.lbl.gov/projects/economic-value-reliability-consumers.

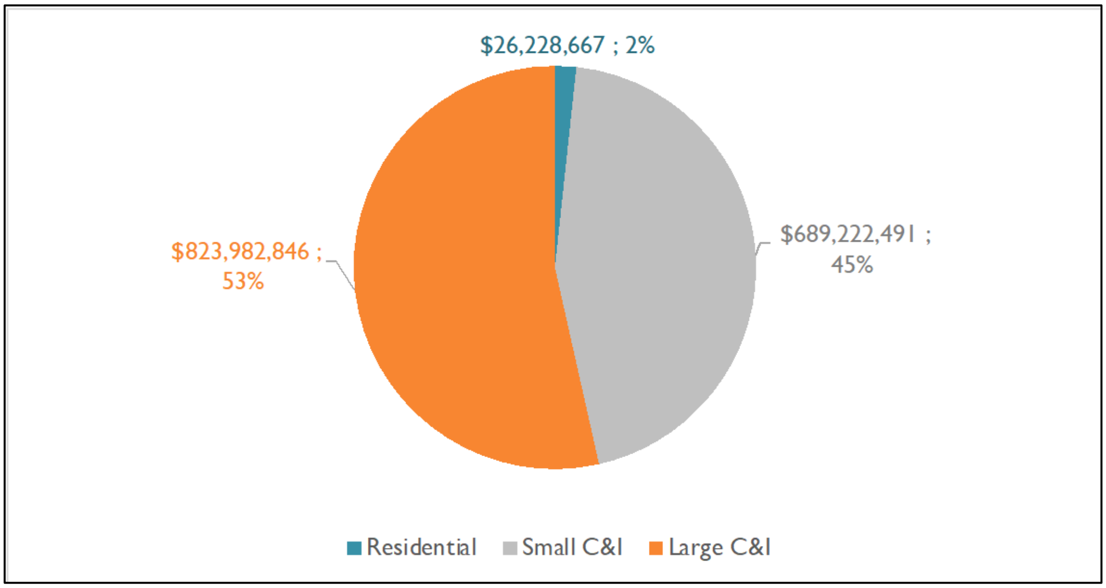
LBNL's analysis finds that "on both an absolute and normalized basis, residential customers experience the lowest costs as a result of power interruption."[65]

Q. What percentage of the reliability benefits will be experienced by residential customers?

A. The Company's CBA demonstrates that residential customers are expected to experience just *2 percent* of the reliability benefits[66] that drive the cost-effectiveness of SOG expenditures. By contrast, these customers pay 61 percent of SOG costs based on the Company's cost allocation.[67]

[65] Michael J. Sullivan et al, *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States* at xii, Lawrence Berkeley National Laboratory (Jan. 2015), https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf.
[66] Calculated from DR ORS 5-13(h), attachment "Conf DEC ORS DR 5-13(h)."
[67] Hager Exhibit 1 provides the amount of plant (distribution, intangible, and general) for each class, which I matched to SOG deferral cost allocations for each type of plant in ORS DR 5. SOG costs were allocated to 17% of intangible plant, 80% distribution plant, 3% general plant, and negligible transmission plant. I then multiplied the percentage of SOG costs for each plant type by the percentage of plant included in the residential class. This resulted in the percentage of SOG costs allocated to the residential class.

Figure 3. Self-Optimizing Grid present value reliability benefits by class (dollars and percent)

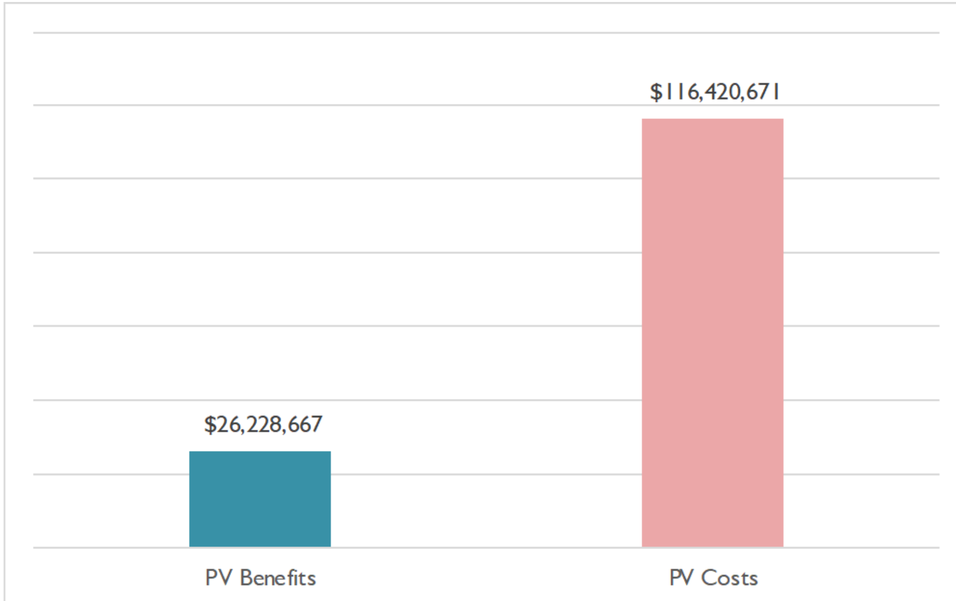


Source: DR ORS 5-13(h), attachment "Conf DEC ORS DR 5-13(h)."

Q. What is the ratio of benefits to costs for residential ratepayers, as calculated by the utility in its CBA?

A. For the residential class, costs significantly exceed benefits. On a present value basis, the BCR of the program is expected to be just 0.23 for residential ratepayers, accounting only for reliability benefits, which comprise 97 percent of total SOG benefits calculated by the utility. I estimated costs of the program to residential ratepayers by allocating the present value costs estimated in the CBA according to the utility's proposed cost allocation to the residential class for SOG costs, 61 percent.

Figure 4. Self-Optimizing Grid present value benefits and costs for the residential class



Source: Calculated from DR ORS 5-13(h), attachment "Conf DEC ORS DR 5-13(h)."

On the other hand, reliability benefits for the commercial classes significantly exceed costs, based on the Company's cost allocation and the fact that VOLL for commercial customers is significantly higher than residential customers.

Q. What are the implications for SOG cost recovery?

A. There is no reasonable justification to approve costs to residential ratepayers for an investment for which residential ratepayers are not expected to experience commensurate benefits, particularly one that goes above and beyond traditional utility compliance requirements (as is the case here). The cost burden for SOG investments that will be imposed on residential ratepayers significantly outweighs the expected benefits.

Q. What do you recommend to remedy this issue?

A. While the Commission could disallow all or a majority (for example, 98 percent) of costs expected to be incurred by residential ratepayers, I recommend instead that cost allocation for these expenditures be set more equitably than the traditional allocator for distribution plant that has been applied to SOG investment costs. This allows customer class benefits to be more proportional with costs. Specifically, I recommend that 95 percent of SOG costs be allocated to commercial and industrial customers, and the remaining 5 percent to the residential class.

Q. Why have you recommended that 5 percent of SOG costs should be allocated to the residential class, and 95 percent to the commercial and industrial classes?

A. As I stated previously, reliability benefits for the SOG program comprise around 97 percent of benefits. The remaining 3 percent of benefits are comprised of capacity savings, energy savings, environmental benefits, and DER enablement,[68] for which it is less straightforward to calculate each class's share of benefits. Since residential ratepayers experience about 2 percent of reliability benefits, I (conservatively) allocate the remaining 3 percent of benefits to residential customers. It is likely that the residential share of these benefits is lower than my assumption. Following the principle of each class paying costs proportional to the benefits received, I therefore recommend 5 percent of SOG costs be allocated to the residential class.

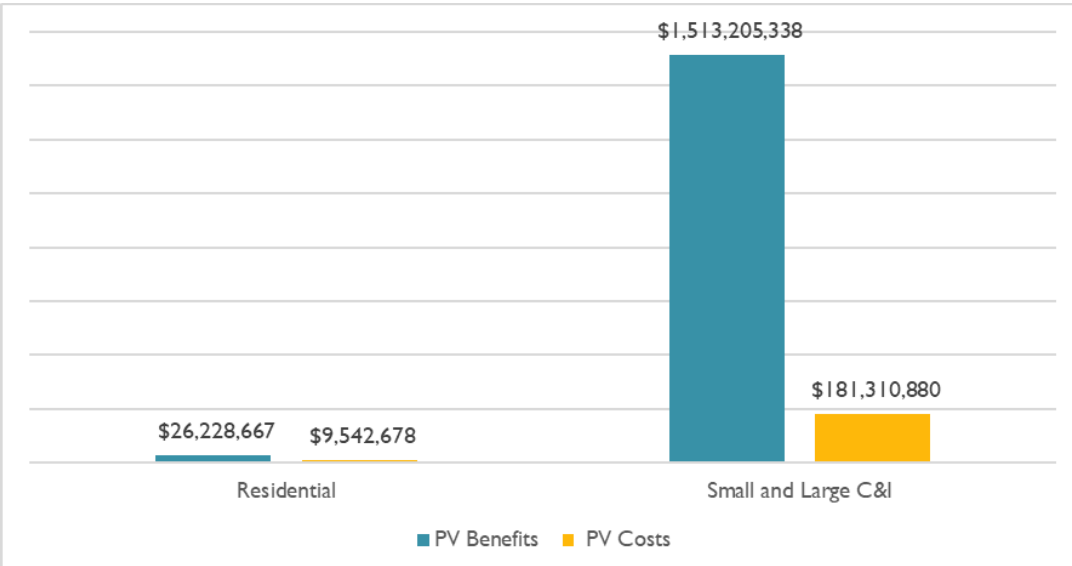
Q. What are the implications of your proposed cost allocation for SOG?

A. If non-residential customers share cost responsibility for the 95 percent of costs weighted by energy billing determinants (kilowatt hours), which was chosen as it is proportional to potential reliability benefits that can be achieved and is a good proxy for class size, this results in a significantly more equitable distribution of reliability benefits and costs on a

[68] DR ORS 5-13(h), attachment "Conf DEC ORS DR 5-13(h)."

present value basis for each class. Under my proposal, BCRs for the residential, and combined small and large commercial and industrial (C&I) classes are 2.75 and 8.35, respectively.

Figure 5. Self-Optimizing Grid present value benefits and costs for all classes, assuming Synapse proposed cost allocation



Source: Calculated from DR ORS 5-13(h), attachment "Conf DEC ORS DR 5-13(h)."

Q. How should the Company implement your proposal to allocate 5 percent of SOG costs to the residential class?

A. The Company should revise its Cost-of-Service Study (COSS) to allocate 5 percent of SOG costs to the residential class, and the remainder to the small and large commercial classes. To provide the Commission with the estimated expected impacts of this approach for depreciation expense, I have adjusted the company's plant-in-service allocations from the COSS to reflect an allocation based on the benefits of the investments, with cost allocations weighted by energy billing determinant (kWh). This adjusts the cost allocation by size of the class and is correlated with benefits, which are based on the value of lost load. The result is the table below.

Table 9. Synapse proposed cost allocation (percent)

	Residential	Small General	Large General	Industrial	Optional TOU - General	Optional TOU - Industrial	Other C&I	Subtotal
Estimated SOG Allocation (DEC)	61%	10%	3%	2%	5%	9%	10%	100%
Synapse Proposed SOG Allocation	5%	9%	7%	8%	20%	45%	5%	100%

Table 10. Estimated impacts on depreciation for Synapse proposed cost allocation ($ Thousand)

	Residential	Small General	Large General	Industrial	Optional TOU - General	Optional TOU - Industrial	Other C&I	Subtotal
Estimated SOG Depreciation (DEC)	$204	$33	$9	$8	$18	$30	$32	$334
Synapse Proposed SOG Allocation	$17	$30	$25	$26	$67	$150	$18	$334
Difference in Depreciation due to Proposal	-$187	-$2	$15	$18	$49	$120	-$14	$0

Source: Calculated from ORS DR AIR 5, "Deferral Actual Costs,"; DEC AIR 1-1, Hager Exhibit 1; DEC ORS AIR 1-1, Beveridge, "Rate Design Workbook V1."

Q. Does your proposal to allocate SOG costs differently than the rest of distribution plant represent a different cost allocation paradigm than traditionally followed by utilities for cost allocation purposes?

A. No. While it does provide a greater focus on the proper allocation of a certain subset of costs than is normally employed, the methodology employed here is entirely consistent with traditional approaches to cost allocation. The Regulatory Assistance Project's

Electric Cost Allocation Manual, for example, explains that a "costs follow benefits" approach is "usually, but not always, the superior principle" to cost allocation.[69]

Traditional cost allocation is based on "cost causation." As Company witness Hager explains, "Under the principle of cost causation, costs are assigned to the specific jurisdictions and customer classes that "caused" such costs to be incurred."[70] Put another way, cost causation asks the question: *why were the costs incurred*?[71] In this case, costs will be incurred to attain the expected benefits, which the Company's CBA shows will accrue predominately to commercial customers. Therefore, the principles of cost causation and allocating costs based on benefits are two sides of the same coin. To be clear, I do not offer an opinion on how other distribution infrastructure costs should be allocated as a general matter. My recommendation is limited to DEC's SOG costs. Unlike standard distribution equipment, SOG costs are not incurred for compliance with the Company's standard obligation to serve. These costs are incurred and proposed to provide benefits beyond traditional utility service obligations, (presumably why the utility has conducted a CBA) and should be allocated in a more equitable manner than proposed by the Company.

Q. Does this conclude your testimony?

A. Yes, it does.

[69] Jim Lazar et al, Electric Cost Allocation for a New Era: A Manual 18 (2020), www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf).
[70] Direct testimony of Janice Hager at page 5.
[71] *Id.* at 25.