STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1219

In the Matter of: Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Services in North Carolina.	)))))	<u>DIRECT TESTIMONY OF WILLIAM E. POWERS ON BEHALF OF NC WARN</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William E. Powers, P.E. My business address is Powers Engineering, 4452 Park Blvd., Suite 209, San Diego, CA 92116.

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

A. My employer is Powers Engineering. I am the founder and principal of the company.

Q. PLEASE BRIEFLY DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I am a consulting and environmental engineer with over 35 years of experience in the fields of power plant operations and environmental engineering. I have worked on the permitting of numerous combined cycle, peaking gas turbine, micro-turbine, and engine cogeneration plants, and am involved in siting of distributed solar photovoltaic (PV) and battery storage projects. I have been an expert witness is high voltage transmission application proceedings in California, Missouri, and Wisconsin, and have evaluated the impact of rooftop solar and battery storage on electric distribution systems for multiple clients. I began my career converting Navy and Marine Corps shore installation projects from oil firing to domestic waste, including wood waste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo in the 1970's.

I authored "San Diego Smart Energy 2020" (2007) and "(San Francisco) Bay Area Smart Energy 2020" (2012), and have written articles on the strategic cost and reliability advantages of local solar over large-scale, remote, transmission-dependent renewable resources. I have a B.S. in mechanical engineering from Duke University, an M.P.H. in environmental sciences from UNC – Chapel Hill, and am a registered professional engineer in California and Missouri.

Q. HAVE YOU EVER TESTIFIED BEFORE THE N.C. UTILITIES COMMISSION (THE "COMMISSION") OR ANY OTHER REGULATORY BODIES IN ANY PRIOR PROCEEDINGS?

A. Yes. I testified on behalf of NC WARN in Docket No. E-7, SUB 1214, Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Services in North Carolina. I testified on behalf of NC WARN in Docket No. EMP-92, SUB 0, Application of NTE Carolinas II, LLC for a Certificate of Public Convenience and Necessity to Construct a Natural Gas-Fueled Electric Generation Facility in Rockingham County, North Carolina. I have also offered affidavit testimony and reports to this Commission in prior dockets, such as Docket No. E-2, Sub 1089. Further, I have offered testimony before other utilities commissions across the country, such as the commissions in California, Missouri, and Wisconsin.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is: 1) to address the need for the Commission to reject the proposed Duke Energy Progress LLC ("DEP") Grid Improvement Plan ("GIP") capital investment program as unreasonable, and 2) to contest cost recovery by DEP for the Asheville natural gas combined-cycle power plant project.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony consists of two parts. Part I will address the reasons why the Commission should reject the GIP as unreasonable. Part II will discuss the reasons why the Commission should reject cost recovery for the Asheville natural gas combined-cycle power plant project.

I. THE GIP SHOULD BE REJECTED

Q. WHY ARE YOU ADVOCATING THE COMMISSION REJECT COST RECOVERY OF THE GIP?

A. DEP has proposed to spend approximately $1.1 billion over three years on its GIP capital projects – many of which Duke Energy Carolinas LLC ("DEC") and the Commission have identified as indistinguishable from traditional spend transmission and distribution (T&D) projects[1] – with no formal application(s) or

[1] DOCKET NO. E-7, SUB 1146 - Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, June 22, 2018, pp. 127-150.

associated evidentiary processes to evaluate the reasonableness of the proposed expenditures or potential alternatives that negate the need for these proposed expenditures.

Q. WHAT IS THE SCOPE OF THE GIP?

A. DEP and DEC (collectively, "Duke Energy") list eighteen separate elements to the GIP, as shown in Table 1, totaling $2,319.2 million, of which DEP's portion is $1,085.8 million. The most expensive single cost element is "Self-Optimizing Grid," with a capital expenditure of $722.5 million shared between DEP and DEC. Ten of these eighteen GIP elements, combined among DEC and DEP, have capital budgets in excess of $100 million. DEP itself proposes three GIP projects with capital budgets in excess of $100 million.

Table 1. Elements and Budgets for 2020-2022 GIP Programs[2]

GIP Program	DEC Budget, $ millions	DEP Budget, $ millions	Total Expenditure, $ millions
Physical & Cyber Security	65.1	68.7	133.8
Self-Optimizing Grid	420.1	302.4	722.5
Integrated Volt/VAR Control	206.7	10.0	216.7
Hardening & Resiliency	102.5	31.3	133.8
Targeted Undergrounding	59.8	54.7	114.5
Energy Storage[3]	56.5	72.5	129.0
Transformer Retrofit	8.3	109.7	118.0
Long Duration Interruptions	11.3	15.8	27.1
Transformer Bank Replacement	33.7	82.7	116.4
Oil Breaker Replacement	115.6	84.7	200.3
Enterprise Communications	103.7	108.1	211.8
Distribution Automation	115.4	78.9	194.3
System Intelligence	62.7	23.7	86.4
Enterprise Applications	17.0	10.8	27.8
ISOP	4.1	2.5	6.6
DER Dispatch	4.5	2.9	7.4

[2] DOCKET NO. E-2, SUB 1219, Duke Energy Progress, LLC, Jay Oliver Direct Testimony, October 30, 2019, Exhibit 10, pdf p. 154.
[3] Duke Energy excludes Energy Storage and Electric Transportation projects from the GIP total.

Electric Transportation	38.2	25.3	63.5
Power Electronics	0.7	1.1	1.8
Total	1,233.4	1,085.8	2,319.2

Q. OTHER THAN DUKE ENERGY'S OWN INTERNAL ANALYSIS AND STAKEHOLDER WORKSHOPS, HAS MORE FORMAL VETTING OF THE GIP OCCURRED?

A. No. DEP witness Oliver stated "DE Progress' Grid Improvement Plan was developed through a comprehensive analysis of the trends affecting our business in the state and the tools to best address those trends in a cost-effective and timely manner."[4] The stakeholder workshops are essentially sales presentations by Duke Energy to stakeholders, many of whom have no technical background in the provision of electric power, on the benefits of the GIP. There has been no formal Commission process to probe whether the alleged benefits are real, whether the benefits justify the costs, or whether alternatives could achieve the same objectives at less cost.

Q. IS IT YOUR POSITION THAT THE STAKEHOLDER WORKSHOPS SPONSORED BY DUKE ENERGY AT THE DIRECTION OF THE COMMISSION ARE AN INSUFFICIENT REVIEW OF THE SCOPE AND COST OF THE GIP?

A. Yes. The high cost of the GIP alone, about $2.3 billion in capital expenditures over three years between DEP and DEC,[5] is sufficient by itself to mandate an additional rigorous review to protect ratepayers. The GIP as proposed also

[4] Direct Testimony of Jay W. Oliver for Duke Energy Progress, LLC, p. 9.
[5] Ibid, Exhibit 10, pdf p. 154. Approximately $1.1 billion is attributable to DEP. See Table 1.

presumes that there is only one pathway to grid modernization and grid hardening, with no assessment of alternatives that may be much less costly and achieve the stated goals more effectively.

Q. DOES DEP INDICATE ITS TRANSMISSION AND DISTRIBUTION GRID IN NORTH CAROLINA IS SAFE AND RELIABLE WITHOUT GIP EXPENDITURES?

A. Yes. DEP Witness Oliver states that "Our (transmission and distribution) system has performed well, and we have continued to provide safe, reliable, and affordable electric service to our customers."[6] He includes a graphic in his testimony showing a DEP Interruption Frequency Index ("SAIFI") that is improving steadily over time. The DEP SAIFI declined about 17 percent between 2011 and 2018.[7] The Interruption Duration Index ("SAIDI") was relatively unchanged from 2015 to 2018.[8] However, Mr. Oliver makes no mention of the SAIFI graphic in his testimony, which undercuts his argument that the GIP is necessary to improve reliability. Mr. Oliver only addresses the SAIDI graphic, saying that "Over the past ten years however, SAIDI shows an unfavorable trend."[9] He ignores the fact that the DEP SAIDI has been relatively unchanged over the last several years (since 2015). The DEP SAIFI and SAIDI trend data presented by Mr. Oliver makes the case that DEP's traditional expenditure levels

[6] DOCKET NO. E-2, SUB 1219, Duke Energy Progress, LLC, Jay Oliver Direct Testimony, October 30, 2019, p. 20.
[7] Ibid, Figure 1, p. 21. SAIFI 2011 = 1.62. SAIFI 2018 = 1.34. (1.62 – 1.34)/1.62 = 0.173 (17.3 percent)
[8] Ibid, Figures 1 and 2, p. 21. The SAIDI and SAIFI figures do not include 2019 data.
[9] Ibid, p. 20.

on transmission and distribution, without GIP, are adequate to provide safe and reliable transmission and distribution service.

Q. CAN YOU GIVE AN EXAMPLE OF WHERE DEP PRESUMES WITHOUT ANALYSIS THAT THERE IS ONLY ONE APPROACH AVAILABLE TO THE IDENTIFIED DEFICIENCY THAT GIP IS INTENDED TO RESOLVE?

A. Yes. An example is the presumption by DEP that targeted undergrounding is the only solution to further reduce outages caused by conductor contact with vegetation. DEP identifies the benefits of targeted undergrounding as: significantly reduce outages, minimize momentary interruptions, restore power faster, eliminate tree trimming in hard-to-access areas.[10]

DEP acknowledges that vegetation contact is responsible for 20 to 30 percent of outages.[11] However, the company implies that its vegetation management program is as good as it can be, and therefore presumptively no further vegetation management improvement is possible: "For the outages that occur because of trees inside the right-of-way, even a perfectly executed integrated vegetation management plan will not bring this number down to zero but instead will only help minimize vegetation outages."[12] DEP also asserts that 50 percent of the vegetation outages are caused by trees located on private

[10] DOCKET NO. E-2, SUB 1219, Duke Energy Progress, LLC Jay Oliver Direct Testimony, October 30, 2019, pdf p. 562.
[11] Ibid, p. 7. "This work seeks to improve overall reliability, harden the grid against severe weather, and reduce the impact of vegetation which currently accounts for 20 to 30 percent of outages across the system."
[12] Ibid, p. 24.

property outside its right-of-way and that it does not have the ability to address these trees.[13] Based on this information, DEP makes the conclusory statement that "Drastic clear cutting and going onto customer property and cutting down live trees via condemnation or negotiating with customers for rights on their property is also impractical and not cost effective."[14] This assertion then introduces the alleged benefits of targeted undergrounding with the statement that "programs such as Targeted Undergrounding . . . can be effectively used to address vegetation outages caused by trees outside of the right-of-way."[15] DEP and DEC collectively propose to spend $114.5 million on targeted undergrounding projects, of which DEP's portion is $54.7 million.[16]

Q. IS DEP'S CONCLUSORY STATEMENT ABOUT THE IMPRACTICALITY OF MORE EFFECTIVE VEGETATION MANAGEMENT A SUFFICIENT BASIS TO JUSTIFY A $114.5 MILLION TARGETED UNDERGROUNDING CAPITAL EXPENDITURE?

A. No. Duke Energy has made clear that a primary objective of the GIP is to increase shareholder value by accelerating the tempo of capital projects.[17] In this context, Duke Energy proposes a combined total of $114.5 million in capital expenditure on targeted undergrounding. The estimated cost of a distribution line overhead-to-

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[13] Ibid, p. 24.
[14] Ibid, p. 24.
[15] Ibid. p. 25.
[16] See, *supra*, Table 1. DEP = $54.7 million, DEC = $59.8 million.
[17] DOCKET NO. E-7, SUB 1146 - Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, June 22, 2018, p. 129. Duke Energy Witness Fountain also admitted that Power / Forward is part of Duke Energy's corporate policy intended, as quoted in a Duke investor earnings call, "to drive 4 to 6 percent earnings growth."

underground conversion is more than $2 million per mile in urban and suburban areas.[18] Based on this undergrounding cost-per-mile, Duke Energy will underground about 60 miles of distribution line in this general rate case cycle, between DEP and DEC targeted undergrounding projects.

Vegetation management is also a tool used by Duke Energy to minimize outages on overhead lines. As noted by Witness Oliver:[19]

> In 2018, the Vegetation Management Plan implemented the seven-year trim cycle for non-urban miles, which had previously been set at six years. The change was based on the result of the Distribution Vegetation Management Species Frequency and Re-Growth Study completed in 2015 conducted to help determine an optimal vegetation maintenance cycle. The study did not result in a change from the three-year trim cycle set for urban miles.

DEP relaxed its non-urban trim cycle from every six years to every seven years in 2018, and left its urban trim cycle unchanged at three years. This is not a situation where DEP has increased the frequency of vegetation trimming in an effort to reduce the 20 to 30 percent of outages caused by vegetation contact. An improved vegetation management program - more frequent than the current non-urban and urban trimming cycles - on about 30 miles of overhead distribution lines that would otherwise be undergrounded by DEP may be able to achieve the same level of outage reduction projected for undergrounding at a fraction of the cost.[20] An improved vegetation management program option should have been

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[18] Pacific Northwest National Laboratory, *Electricity Distribution System Baseline Report*, July 2016, p. 40. See: https://www.energy.gov/sites/prod/files/2017/01/f34/Electricity%20Distribution%20System%20Baseline%20Report.pdf.

[19] DOCKET NO. E-2, SUB 1219, Duke Energy Progress, LLC, Jay Oliver Direct Testimony, September 30, 2019, p. 23.

[20] ($54.7 million ÷ $114.5 million) × 60 miles = 28.7 miles.

considered to assure that any expenditures on targeted undergrounding are just and reasonable for ratepayers.

Q. ARE THERE REASONABLE AND PRACTICAL ALTERNATIVES TO DEP'S UNDERGROUNDING PLAN BEYOND ENHANCED VEGETATION MANAGEMENT?

A. Yes. It would be practical and less costly to put battery storage in every home along a proposed distribution line undergrounding route. Green Mountain Power ("GMP"), a Vermont investor-owned utility, implemented a virtual power plant ("VPP") in 2017, approved by the Vermont Public Utility Commission, consisting of aggregating and dispatching up to 2,000 residential Tesla Powerwall™ battery storage units.[21,22] GMP customers participating in this program have the option to purchase the Powerwall™ for a one-time cost of $1,500 or $15 per month over ten years.[23] The first phase of this project, consisting of 500 Powerwall™ units, saved GMP more than $500,000 over several days during a 2018 summer heat wave.[24] Assuming the presence of a comparable program in Duke Energy North Carolina territory, whether DEP or DEC service territory, it would cost about $300,000 per mile to equip every home in a North Carolina neighborhood with a

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[21] The Tesla Powerwall™ has a discharge capacity of 5 kilowatts (kW) continuous and a storage capacity of 13.5 kW-hours. See: https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf.

[22] Green Mountain Power, *Notification - Tesla Powerwall Grid Transformation Innovative Pilot*, submitted to Vermont Public Utility Commission, July 31, 2017. See: http://apps.psc.wi.gov/pages/viewdoc.htm?docid=364977.

[23] Ibid, p. 2.

[24] Utility Dive, *Tesla batteries save $500K for Green Mountain Power through hot-weather peak shaving*, July 23, 2018. See: https://www.utilitydive.com/news/tesla-batteries-save-500k-for-green-mountain-power-through-hot-weather-pea/528419/.

Tesla Powerwall™.[25] $300,000 per mile to assure reliability during outages in every home along a distribution line pathway is a small fraction of the more than $2 million per mile for an overhead-to-underground distribution line conversion along the same route. The home battery storage option is an example of alternatives to the undergrounding capital budget that have not been examined or deployed by DEP.

Q. DUKE ENERGY PROPOSES CAPITAL EXPENDITURES OF $133.8 MILLION FOR "HARDENING AND RESILIENCY," OF WHICH $31.3 MILLION IS RELATED SPECIFICALLY TO DEP. WHAT IS HARDENING AND RESILIENCY?

A. The company defines transmission and distribution hardening and resiliency capital projects as: alternate power feeds for substations in flood-prone areas, hardening distribution line river crossings, improved guying for at-risk structures within flood zones, 44-kV system upgrades, targeted line rebuild for extreme weather, networking radially served substations, and substation flood mitigation.[26] However, DEP also acknowledges that ". . . energy storage solutions may offer more cost-effective solution(s) for improving reliability and managing costs."[27] Witness Oliver includes a description of the Hot Springs, NC microgrid project as an example of Duke Energy using battery storage and solar power to substitute for

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[25] Assume each home has a street-front property length of 50 feet. Therefore, there are about 100 homes per mile on each side of the street (5,280 feet per mile ÷ 50 feet per home = 105.6 homes per mile per side of street), or about 200 homes per mile total. 200 homes/mile × $1,500/home = $300,000 per mile. This cost does not include homeowner investment in an associated solar power system.
[26] DOCKET NO. E-2, SUB 1219, Duke Energy Progress, LLC Jay Oliver Direct Testimony, October 30, 2019, Exhibit 12, p. 66 and p. 78.
[27] DOCKET NO. E-2, SUB 1219, Duke Energy Progress, LLC Jay Oliver Direct Testimony, October 30, 2019, pdf p. 105.

building a redundant line to provide back feed capability to a vulnerable community.[28] Notably, DEP filed an application in 2018 for a certificate of public convenience and necessity to build the Hot Springs microgrid project.[29] However, there is no discussion in Witness Oliver's testimony as to whether the battery storage microgrid approach is less costly than building redundant lines to serve vulnerable communities, and therefore should be the preferred method of protecting these vulnerable communities.

Q. DUKE ENERGY PROPOSES CAPITAL EXPENDITURES OF $722.5 MILLION ON THE "SELF-OPTIMIZING GRID." WHAT IS A SELF-OPTIMIZING GRID?

A. Duke Energy proposes to spend $722.5 million, $302.4 million by DEP and $420.1 million by DEC, on Self-Optimizing Grid technologies.[30] Witness Oliver states that "the Self-Optimizing Grid, also known as the smart-thinking grid, redesigns key portions of the distribution system and transforms it into a dynamic self-healing network that ensures many issues on the grid can be isolated and customer impacts are limited to hundreds versus thousands. These grid capabilities are enabled by installing automated switching devices to divide circuits into switchable segments that will serve to isolate faults and automatically reroute power around trouble areas which call for expanding line and substation

[28] Id., pdf p. 270.
[29] Duke Energy Progress, LLC, *Application for Certificate of Public Convenience and Necessity - Hot Springs Microgrid Solar and Battery Storage Facility*, Docket No. E-2, Sub 1185, October 8, 2018, p. 7. Hot Springs is a remote town of 500 people in the Appalachian Mountains served by a single distribution line that is subject to frequent outages. DEP plans to install approximately 3 MW of solar power and 4 megawatt-hours (MWh) of lithium battery storage and configure circuits to allow Hot Springs to isolate from the grid as needed, known as "islanding," when grid power is unavailable.
[30] See Table 1.

capacity to allow for two-way power flow and creating tie points between circuits."[31] In a single sentence, DEP mixes talk of switching devices to isolate faults with expanding line and substation capacity to allow for two-way power flow. There is no analysis of alternatives that might achieve the same distribution grid reliability improvement at less cost to ratepayers. DEP also implies that the impact of outages will be reduced by 90 percent or more ("limited to hundreds versus thousands") by deploying the Self-Optimizing Grid, but no evidence is offered to support or clarify what DEP means by "impact of outages" or how it calculated the precipitous decline in impacts.

Q. IS EXPANSION OF LINE AND SUBSTATION CAPACITY NECESSARY TO ENABLE TWO-WAY POWER FLOW CAUSED BY HIGH LEVELS OF DISTRIBUTED ENERGY RESOURCES (AKA ROOFTOP SOLAR)?

A. No. Installing rooftop solar with battery storage in homes and businesses can achieve the same purpose. An October 2017 study commissioned by the California Public Utilities Commission ("CPUC"), *Customer Distributed Energy Resources Grid Integration Study - Residential Zero Net Energy Building Integration Cost Analysis*,[32] examined the degree to which grid upgrades would be necessary to absorb rooftop solar flows in neighborhoods where all homes have rooftop solar. The context of the 2017 study is the California mandate that all new residences built in 2020 or later are zero net energy homes with rooftop

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[31] Direct Testimony of Jay W. Oliver, p. 35.
[32] DNV NL, *Customer Distributed Energy Resources Grid Integration Study - Residential Zero Net Energy Building Integration Cost Analysis*, prepared for CPUC, October 2017. "This study was conducted to inform the next CPUC net-energy metering (NEM) policy revisit (now anticipated for summer 2020)," p. vii.

solar.[33] The study was in effect a "worst case" assessment of the existing grid's ability to absorb distributed solar inflows when all homes on a circuit are generating solar power and potentially exporting some or all of that solar power to the grid at the same time.

Q. IS IT YOUR POSITION THAT ADDING SOLAR AND BATTERY STORAGE AT HOMES AND BUSINESSES ACHIEVES THE SAME END WITHOUT THE POTENTIAL FOR STRANDED INVESTMENTS IN GRID OPTIMIZATION?

A Yes. Distribution circuits are typically designed to accommodate double or more of the expected peak load on the circuit.[34] The basis for this is to provide sufficient capacity to ensure each circuit can serve as a backup source of power to an adjacent circuit in case of an outage on the adjacent circuit. In this context, the 2017 California study examined rooftop solar inflows (i.e. two-way flow) up to 160 percent of the base case peak load of the distribution circuit being analyzed. The study determined that simple steps, such as use of "smart" solar inverters and good distribution of the solar systems along the circuit, could substantially increase the capacity of the circuit to absorb solar inflows with little or no cost.

The 2017 study also determined that, without battery storage, incrementally more extensive grid upgrades would potentially be necessary, including regulator control upgrades, re-close blocking, reconductoring of overloaded circuit sections, and/or additional voltage regulators, to address grid

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[33] New York Times, *California Will Require Solar Power for New Homes*, May 9, 2018: https://www.nytimes.com/2018/05/09/business/energy-environment/california-solar-power.html.
[34] The thermal rating of the conductors determines the maximum power flow.

reliability issues. However, the addition of battery storage with the rooftop solar would negate the need for progressively more expensive grid optimization upgrades. The report states that ". . . energy storage could be deployed to mitigate all violations on the circuit rather than deploying other measures at lower penetrations that would later become redundant."[35] In this case, DEP is proposing grid optimization measures that will become redundant if battery storage is integrated with rooftop solar. The deployment of battery storage with rooftop solar systems is projected to rapidly become a standard industry practice.[36]

The 2017 study concludes its assessment of the grid reliability value of battery storage stating ". . . (battery storage) could prove much more cost-effective in the long run particularly given the other functions that are available from distributed energy storage systems. If energy storage was implemented at the buildings or circuits . . . then the associated integration costs identified in this study would be negated." In sum, if an appropriate capacity of battery storage is included with solar installations in neighborhoods where 100 percent of the homes have rooftop solar, no additional "grid optimization" would be necessary to the existing distribution grid.

Q. IS ANOTHER STATE EXPECTING TO ADD ABOUT 3,000 MW OF RESIDENTIAL AND COMMERCIAL BATTERY STORAGE FOR

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[35] DNV NL, *Customer Distributed Energy Resources Grid Integration Study - Residential Zero Net Energy Building Integration Cost Analysis*, prepared for CPUC, October 2017, p. xv. "This study was conducted to inform the next CPUC net-energy metering (NEM) policy revisit (now anticipated for summer 2020)," p. vii.

[36] Greentech Media, *10 Rooftop Solar and Storage Predictions for the Next Decade*, January 3, 2020: https://www.greentechmedia.com/articles/read/10-rooftop-solar-and-storage-predictions-for-the-next-decade.

ABOUT THE SAME COST AS DUKE ENERGY'S $722.5 MILLION SELF-OPTIMIZING GRID CAPITAL BUDGET?

A. Yes. California Senate Bill SB 700 was signed into law in late September 2018 and is expected to add, with an incentive budget of $830 million, up to 3,000 MW of behind-the-meter residential and commercial storage in California by 2026.[37]

Q. IS THE CONSERVATIVE DEFAULT SOLAR CAPACITY OF DEC AND DEP DISTRIBUTION FEEDERS ALREADY SIX TIMES HIGHER THAN THE GIP SMART GRID OPTIMIZATION TARGET OF 835 MW?[38]

Yes. According to the National Renewable Energy Laboratory, the default rule-of-thumb for solar capacity on a distribution feeder - without any need for study - is 15 percent of peak load.[39] The summer peak loads in DEP and DEC service territories in 2018 were 12,841MW and 17,632 MW, respectively, or approximately 30,500 MW.[40,41] Using this rule-of-thumb, the total default "as is" solar hosting capacity of the DEC and DEP's North Carolina distribution feeders is in the range of 30,500 MW × 0.15 = 4,575 MW. This is more than five times higher than the stated GIP Smart Grid Optimization solar capacity goal of 835 MW. There is no justification for a Smart Grid Optimization solar capacity goal

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[37] Greentech Media, *California Passes Bill to Extend $800M in Incentives for Behind-the-Meter Batteries*, August 31, 2018, https://www.greentechmedia.com/articles/read/california-passes-bill-to-extend-incentives-for-behind-the-meter-batteries#gs.6cxCMs0.

[38] Opening Testimony of Jay W. Oliver, pdf p. 470. "SOG increases hosting capacity from approximately 496 MW to 835 MW."

[39] National Renewable Energy Laboratory (NREL), *Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders*, July 2012, p. 1. See: https://www.nrel.gov/docs/fy12osti/55094.pdf. "A commonly used rule of thumb in the U.S. allows distributed PV systems with peak powers up to 15% of the peak load on a feeder (or section thereof) to be permitted without a detailed impact study [4]. This necessarily conservative rule has been a useful way to allow many distributed PV systems to be installed without costly and time-consuming distribution system impact studies."

[40] 2018 DEP FERC Form 1, April 12, 2019, p. 401b (12,841 MW, June 19, 2018).

[41] 2018 DEC FERC Form 1, May 29, 2018, p. 401b (17,632 MW, June 19, 2018).

of 835 MW, as far more than 835 MW is already available, and any capital expense justified as necessary to achieve this goal is unreasonable.

Q. IS THE SELF-OPTIMIZING GRID NECESSARY TO ACHIEVE A CUSTOMER SOLAR CAPACITY OF 835 MW?

A. No. In addition to the rule-of-thumb identified by the National Renewable Energy Laboratory, the Department of Energy has sponsored numerous studies to estimate the solar capacity of utility distribution systems. One study involved the Dominion Virginia Power (DVP) distribution system.[42] DVP evaluated 14 representative distribution feeders from an overall distribution feeder population of 1,813 in its service territory.[43] The DVP summer peak load of 15,570 MW is comparable to the 2018 DEP and DEC peak loads of 12,841 MW and 17,632 MW,[44] respectively. DVP evaluated the percentage of thermal rating of the feeder available for solar hosting as upgrades were added. This necessitates understanding the relationship between peak load on the feeder and the thermal rating of the feeder.

The feeder thermal rating, meaning the point at which overhead feeders sag excessively due to the high temperature of the conductor or at which underground feeders approach the temperature where the insulation could begin to melt, is typically 2 to 3 times the peak load on the feeder.[45] Conversely, 100

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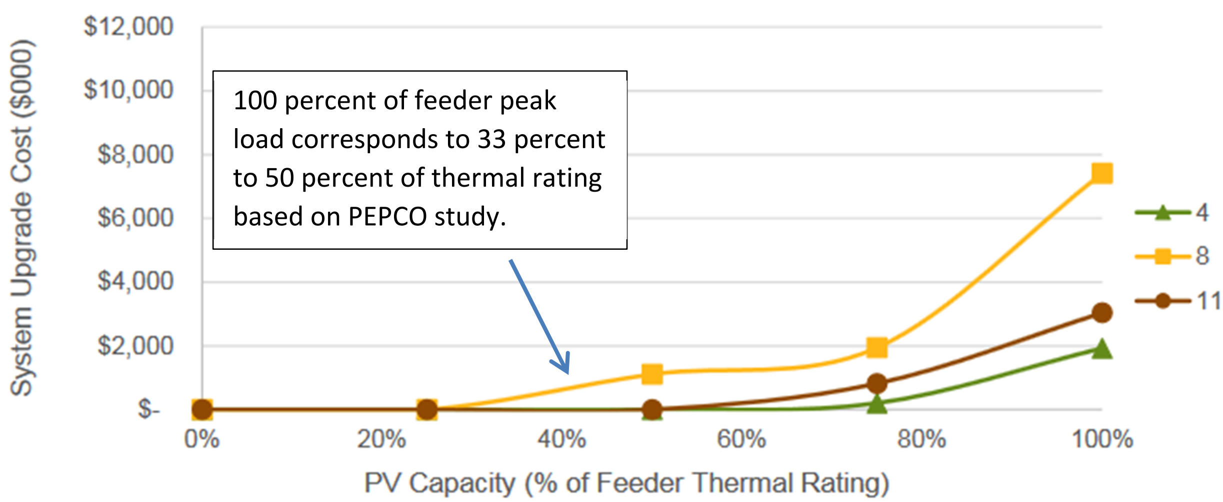
[42] An affiliated company of DVP, Dominion North Carolina, is regulated by NCUC.
[43] B. Powers, *North Carolina Clean Path 2025*, August 2017, pp. 73-74, filed by NC WARN in the 2017 IRP docket, E-100, Sub 147.
[44] DEP 2018 FERC Form 1, April 12, 2019, p. 401b.
[45] Ibid., B. Powers, *North Carolina Clean Path 2025*, August 2017, Table 30a Increase in Solar Hosting Capacity and Upgrade Cost for Top 12 of 20 PEPCO Feeders Evaluated, p. 72. The 2015 PEPCO study sponsored by DOE evaluated feeder upgrades necessary to increase distribution feeder solar hosting capacity to up to 300 percent of the actual feeder peak load. See: DOE, *Model-Based Integrated High*

percent of peak load is approximately 33 to 50 percent of the feeder thermal rating, depending on the individual feeder. This is an important relationship to understand to interpret the DVP results. The results shown in Figure 1 are for the three feeders selected by DVP for presentation, and assume that smart solar inverters – without battery storage – are utilized to optimize voltage at the point of interconnection between the solar array and the feeder.

Figure 1. Cost Versus Improvement in Solar Hosting Capacity for Selected DVP Feeders Assuming Use of Advanced Solar Inverters
(source: Navigant)[46]



The most representative feeder among the three shown in Figure 1, in the opinion of Powers Engineering, is Feeder 11. This feeder serves a predominantly residential load, as do most of the fourteen representative feeders included in the DVP study. In contrast, Feeder 8 serves a predominantly commercial load and is representative of only about 1 percent of the 1,813 feeders in the DVP service

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Penetration Renewables Planning and Control Analysis for PEPCO Holdings - Final Report, December 10, 2015 (https://www.osti.gov/servlets/purl/1229729).
[46] B. Powers, *North Carolina Clean Path 2025*, August 2017, Figure 14, p. 74, filed by NC WARN in the 2017 IRP docket, E-100, Sub 147.

territory. Feeder 4 is somewhat of an outlier, representing low voltage (4.16 kV) and very short (3 miles) feeders. No significant solar hosting upgrade costs are encountered on Feeder 11 until about 67 percent of the thermal rating is reached, which equates to 133 to 200 percent of feeder peak load.[47] This data implies that the Duke Energy North Carolina distribution grid, including DEP and DEC service territories, with a summer peak load of approximately 30,500 MW, could meet that peak load with distributed solar power – and without battery storage – with little or no upgrading. In contrast DEP presumes, with no analysis, that its base case distributed solar hosting capacity without the Self-Optimizing Grid program is only 496 MW.

Q. HAS ANY OTHER STATE UTILITY COMMISSION RULED ON THE REASONABLENESS OF SELF-OPTIMIZING GRID EXPENDITURES?

A. Yes. Virginia's State Corporation Commission rejected Dominion's self-healing grid proposal in March 2020 saying that the utility failed to provide evidence of reliability improvements.[48]

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[47] DOE, *Model-Based Integrated High Penetration Renewables Planning and Control Analysis for PEPCO Holdings - Final Report*, December 10, 2015 (https://www.osti.gov/servlets/purl/1229729). The 2015 PEPCO study sponsored by DOE evaluated feeder upgrades necessary to increase distribution feeder solar hosting capacity to up to 300 percent of the actual feeder peak load.

[48] GreenTech Media, *Virginia Regulators Reject Key Parts of Dominion's Smart Meter, Grid Upgrade Plan*, March 27, 2020: https://www.greentechmedia.com/articles/read/virginia-regulators-reject-most-expensive-parts-of-dominions-grid-modernization-smart-meter-plan. "The SCC also rejected Dominion's plan for 'self-healing grid' automation technologies, expected to cost $241.5 million in the first phase and $2.1 billion over 10 years, stating that the utility failed to provide evidence of the reliability improvements that could come from such an 'expensive and sweeping' deployment. . . Also rejected was one of the most expensive parts of Dominion's grid-hardening plan, which would have directed $70 million in its first phase and $1.2 billion over the next 10 years to perform 'proactive' upgrades of substation and service transformers identified as being at risk of failure or overloading."

II. ASHEVILLE COMBINED CYCLE POWER PLANT

Q. WHAT IS THE CAPITAL COST AND SCOPE OF THE ASHEVILLE NATURAL GAS COMBINED CYCLE POWER PLANT?

A. DEP requests approximately $770 million in recovery in this rate case for the Ashville combined cycle power plant.[49] DEP announced the Western Carolinas Modernization Plan in November 2015, which included retirement of the existing Asheville coal-fired plant and the construction of two 280 MW combined-cycle natural gas plants having dual-fuel capability.[50] DEP estimated a capital cost of $893 million for the Asheville combined cycle project in its March 2018 progress report to the Commission.[51] Both phases of the combined cycle project were online as of April 5, 2020.[52,53]

Q. WHAT IS THE PRODUCTION COST OF A COMPARABLE COMBINED CYCLE UNIT?

A. No actual production costs have yet been reported for the Asheville combined cycle project. Production costs are available for other DEP combined cycle projects. The most recently constructed combined cycle power plant in DEP's system, prior to the Asheville plant, was the H. F. Lee combined cycle plant in

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[49] *See generally* Direct Testimony of Julie K. Turner, a pp. 6-7.
[50] DEP FERC Form 1, April 12, 2019, pdf p. 80.
[51] Ibid.
[52] Duke Energy Progress, LLC, *Western Carolinas Modernization Project Annual Progress Report Docket No. E-2, Sub 1089*, March 30, 2020. "As noted in the report, DEP continues to work with the original equipment manufacturer to repair a manufacturing defect in the Unit 8 Steam Turbine Generator of Power Block 2 and currently expects to place the Unit 8 Steam Turbine Generator into commercial operation in April 2020."
[53] Duke Energy Progress, LLC, *Western Carolinas Modernization Project Status Update - Docket No. E-2, Sub 1089*, April 6, 2020. "On April 5, 2020, the Unit 8 Steam Turbine Generator of Power Block 2 of the Asheville Combined Cycle Project went into commercial operation."

Wayne County, North Carolina. This 920 MW combined cycle project came online in December 2012.[54] The production cost in 2018 of DEP's 920 MW H. S. Lee combined cycle project was $36/MWh in 2018.[55]

Q. IS IT REASONABLE TO ASSUME THAT THE ASHEVILLE COMBINED CYCLE POWER PLANT WOULD HAVE A PRODUCTION COST COMPARABLE TO THE W.S. LEE COMBINED CYCLE PROJECT?

A. Yes. The two combined cycle plants are the same design and similar combustion efficiency, either new or recently constructed, and use the same fuel with presumably a similar cost.

Q. WHAT IS THE PRODUCTION COST OF HYDROELECTRIC UNITS?

A. About $13/MWh, or one-half to one-third the expected production cost of the Asheville combined cycle units.[56]

Q. ARE EXISTING REGIONAL MERCHANT COMBINED CYCLE AND HYDROELECTRIC PLANTS AVAILABLE TO SUPPLY DEP WITH LOWER-COST POWER THAN POWER FROM THE ASHEVILLE COMBINED CYCLE POWER PLANT?

A. Yes. I addressed this issue in July 2016 in DOCKET NO. E-2, SUB 1089, "Application of Duke Energy Progress, LLC for a Certificate of Public Convenience and Necessity to Construct a 752 MW Natural Gas-Fueled

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[54] Duke Energy, H.F. Lee Plant, webpage accessed March 31, 2020: https://www.duke-energy.com/our-company/about-us/power-plants/h-f-lee-plant.
[55] Ibid, p. 403.3 (920 MW H.F. Lee combined cycle plant, expenses per net kWh = $0.0357/kWh – line 35).
[56] DEC FERC Form 1, May 29, 2019, p. 406.1 (Cowans Ford hydro plant, 350 MW, expenses per net kWh = $0.0129/kWh – line 35).

Electric Generation Facility in Buncombe County Near the City of Asheville."[57] The affidavit filed by NC WARN on my behalf in DOCKET NO. E-2, SUB 1089, which affidavit remains both accurate and pertinent today, stated that "DEP West has available off-the-shelf hydropower and combined cycle gas turbine options in the region to supply capacity if additional capacity is needed . . . Four Smoky Mountain Hydro units near the North Carolina-Tennessee border have a capacity of 378 MW and produce 1.4 million MWh annually. These units are in the TVA system, which is connected to DEP West by a single 161 KV line from TVA to the substation at the Walters Hydro Plant in DEP West. The power produced by these units is not currently contracted for purchase. . ." This is an example of a lower-cost regional power supply that could have been contracted to avoid the substantial DEP capital expenditures to build the 560 MW Asheville combined cycle plant. There is also currently nearly 50,000 MW of low-cost merchant combined cycle capacity in the PJM Interconnection regional market,[58] adjacent to DEP territory, potentially available for contracting by DEP at or below the production cost of the Asheville combined cycle plant.[59] Relying on these existing

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[57] DOCKET NO. E-2, SUB 1089 - Application of Duke Energy Progress, LLC for a Certificate of Public Convenience and Necessity to Construct a 752 MW Natural Gas-Fueled Electric Generation Facility in Buncombe County Near the City of Asheville, *Affidavit of William E. Powers for NC WARN and The Climate Times*, June 27, 2016.

[58] Monitoring Analytics, LLC, *2019 Quarterly State of the Market Report for PJM: January through March*, May 9, 2019, p. 65. See: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019q1-som-pjm.pdf. As of March 31, 2019, there was 47,591.6 MW of operational combined cycle capacity in PJM.

[59] U.S. Energy Information Administration, *Natural gas-fired power plants are being added and used more in PJM Interconnection*, October 17, 2018. See: https://www.eia.gov/todayinenergy/detail.php?id=37293. Combined cycle units in PJM generated about 200 million MWh in 2017, at an average capacity factor of about 60 percent.

regional combined cycle and/or hydroelectric resources would avoid DEP ratepayers having to pay the capital cost of the Asheville combined cycle plant.

Q. IS BATTERY STORAGE ALREADY CAPABLE OF PRODUCING POWER FOR LESS THAN A $20/MWH PRODUCTION COST, WELL BELOW THE PRODUCTION COST OF THE ASHEVILLE COMBINED CYCLE PROJECT?

A. Yes. Los Angeles Department of Water and Power signed a 25-year contract for the 300 MW Eland solar and battery storage project in September 2019.[60] The production cost of the battery storage component of the project is approximately $0.02/kWh.[61] The project includes four hours of battery storage at rated capacity.[62] The cost of battery storage capacity continues to decline at a rapid rate.[63]

Q. COULD THE ADDITION OF BATTERY STORAGE TO THE NEARLY 6,000 MW OF UTILITY-SCALE SOLAR IN NORTH CAROLINA ACHIEVE THE SAME PURPOSE AS THE ASHEVILLE COMBINED CYCLE PROJECT?

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[60] PV Magazine USA, *Los Angeles says "Yes" to the cheapest solar plus storage in the USA*, September 10, 2019. See: https://pv-magazine-usa.com/2019/09/10/los-angeles-commission-says-yes-to-cheapest-solar-plus-storage-in-the-usa/.

[61] Ibid. "The final version of the project delivered will in fact be a 300 MW / 1.2 GWh energy storage installation – with an aggregate pricing of 3.962¢/kWh. The project was originally offered at a record US price of 1.997¢/kWh for solar power alone." The incremental cost of the battery storage = 3.962¢/kWh - 1.997¢/kWh = 1.965¢/kWh (~$0.01965/kWh).

[62] Ibid.

[63] CNBC, *The battery decade: How energy storage could revolutionize industries in the next 10 years*, December 30, 2019. See: https://www.cnbc.com/2019/12/30/battery-developments-in-the-last-decade-created-a-seismic-shift-that-will-play-out-in-the-next-10-years.html.

A. Yes. This approach could be used on the nearly 6,000 MW of solar farms in North Carolina[64] to smooth-out solar generation and provide dispatchable peaking power.

Q. WOULD THIS APPROACH IMPOSE ANY CAPITAL COST BURDEN ON DEP RATEPAYERS?

A. No. The cost of battery storage additions would be borne by the third-party owners of the solar facilities. However, Duke Energy has opposed allowing solar facility owners to add battery storage. As noted by NCSEA Witness Tyler Harris, "Duke Energy is proposing unjust and unreasonable barriers to market entry for energy storage resources – particularly with respect to power purchase terms and conditions and interconnection standards – that will wholly obstruct the addition of such resources to the vast majority of installed renewable generating facilities in North Carolina."[65] Duke Energy has spent approximately $820 million building the Asheville combined cycle power plant – resulting in the DEP request in this general rate case to recover approximately $770 million – that could have been avoided by simply allowing existing solar facilities in North Carolina to add battery storage at their own expense in return for reasonable payment for the added value of the storage capacity.

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[64] Solar Energy Industries Association, *State Solar Spotlight: North Carolina*, at https://www.seia.org/sites/default/files/2019-12/North%20Carolina.pdf.
[65] Docket No. E-100, Sub 158, Direct Testimony of Tyler H. Norris on behalf of NCSEA, July 3, 2019, p. 8.

Q. IN LIGHT OF THE ABOVE, SHOULD DEP RATEPAYERS HAVE TO PAY FOR THE CONSTRUCTION OF THE ASHEVILLE COMBINED CYCLE PROJECT JUST BECAUSE IT IS ALREADY BUILT?

A. No. As described above, DEP's investment in the Asheville combined cycle project was not needed. Moreover, both phases of the Asheville combined cycle project were not online until April 5, 2020. Hence, the project cannot be considered "used and useful." Moreover, for the reasons described above, the Asheville combined cycle project was not the least-cost mix of generation. For all of these, among others, the significant expense of the Asheville combined cycle project was not reasonably and prudently incurred. Accordingly, DEP should not be reimbursed by ratepayers for the Asheville combined cycle project.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document upon counsel for all parties to this docket by email transmission.

This the 13th day of April, 2020.

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