Report on Duke Energy 2018 IRPs and Proposed Grid Modernization Program

Bill Powers, P.E., January 16, 2019

I. Introduction

Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (collectively "Duke Energy") are Duke Energy Corporation's two investor-owned electric utilities ("IOU") in North Carolina.[1] Vertically-integrated IOUs such as Duke Energy operate as private monopolies that receive a fixed rate of return (gross profit) on steel-in-the-ground construction, including transmission and distribution lines, power plants, meters, and pipelines. Duke Energy is currently advancing an ambitious $20+ billion conventional build-out of transmission, distribution, and gas-fired generation.

Rate recovery for DEC proposed $13 billion Power/Forward Carolinas transmission and distribution (T&D) modernization project was denied by the North Carolina Utilities Commission (NCUC) in June 2018.[2] However, DEC was directed in that decision to "resolve some or all of the issues surrounding (Power/Forward) grid modernization and the most appropriate cost recovery mechanism for such costs" in the Integrated Resource Planning (IRP) and Smart Grid Technology dockets.[3] A recurrent observation by the NCUC in its June 2018 denial was the routine nature of many of the elements of Power/Forward,[4] and therefore the lack of justification for special treatment via a bill rider.

Duke Energy lobbyists unsuccessfully attempted in 2017 to have legislation enacted, SB 619, that would create the grid modernization rider by statute.[5]

Duke Energy is also proposing, through the DEC and DEP 2018 IRPs, to add nearly 10,000 MW of new gas-fired power plant capacity over the next 15 years. The estimated capital cost of this new gas-fired capacity is in the range of $10 billion. Duke Energy is also proposing to add only 230 MW of battery storage. In contrast, solar with battery storage is already more competitive on cost than gas-fired peaker turbine capacity in some parts of the country. Battery storage dominance of the peaker application is projected by the mid-2020s.

The 2018 Duke Energy IRPs propose to slow the rate of new solar capacity to about one-quarter the actual rate of solar capacity additions over the last four years. Duke Energy is also impeding

[1] Duke Energy, consisting of DEC and DEP, is the predominant electric IOU provider in North Carolina, supplying over 90 percent of the electricity consumed in the state.
[2] NCUC Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, DOCKET NO. E-7, SUB 1146, June 22, 2018, p. 128, 329.
[3] Ibid, pp. 329-330.
[4] Ibid, p. 132. "As to the distinction between Power/Forward spend and customary spend, (Duke) witness Simpson testified on cross-examination that a layperson or even an engineer from an electric cooperative may not be able to distinguish Power/Forward construction from customary spend construction."
[5] Ibid, p. 135.

the ability of new non-utility solar projects to include battery storage. Duke Energy forecasts in its 2018 IRPs that it will generate a percentage of only 8 percent of renewable energy by 2033.

Duke Energy Corporation has assured shareholders that it will initiate numerous rate cases in North Carolina over the next several years to assure strong returns.[6] Former President of Duke Energy Carolinas, David Fountain's testimony acknowledged that was the point of Power/Forward.[7] The strategic plan(s) in Duke Energy's 2018 IRPs ignore the most cost-effective and environmentally-sound solutions to the grid reliability in favor of routine infrastructure additions apparently selected to maximize shareholder returns.

II. Duke Energy Capital Infrastructure Bias – Building More Conventional Infrastructure

It is instructive to understand the background of IOU rate recovery to put the Duke Energy 2018 IRPs in perspective. Congress first legislated the current IOU accounting structure in *The Natural Gas Act* of 1938. The Federal Power Commission (now Federal Energy Regulatory Commission – FERC) established this revenue structure in a proceeding involving a pipeline company transporting natural gas from West Virginia to customers in Ohio and Pennsylvania. The Supreme Court affirmed in 1944 the constitutionality of this structure in its *Hope Natural Gas* decision.[8]

The *Hope* regulatory structure favors return on investment from fixed capital projects. The system works in the following manner: A public service commission, NCUC, first determines the revenue requirement of the utility by adding a reasonable rate-of-return to the value of the "rate base."[9] The rate base is the infrastructure owned by the IOU. Rates for the different service classes, including residential, commercial, and industrial, are then set to cover this rate base revenue requirement. Other costs that are spread across the service classes include operations, maintenance, overhead expenses, and wholesale power purchases.

Utilities increase their revenues by building capital expenditure ("capex") projects under the *Hope* framework. This is the root of IOU "capex bias." Capex bias is a direct artifact of the *Hope* regulatory framework, not a natural or inevitable economic development. Duke Energy asserts that one reason for pursuing Power/Forward is to accommodate green distributed energy resources (DER).[10] Yet Duke Energy proposes no strategy to accelerate green DER adoption. The

[6] Duke Energy Corporation Fourth Quarter 2017 Earnings Review and Business Update p. 16
[7] Ibid, p. 129. "(Former President of Duke Energy Carolinas, David Fountain) acknowledged that Duke Energy represented to its investors that it would pursue (Power/Forward) distribution infrastructure riders to enhance investment returns."
[8] R. Astoria – The Electricity Journal, *On the radicality of New York's Reforming the Energy Vision*, 2017.
[9] Ibid, p. 3 of 5.
[10] Duke Energy, *2018 Smart Grid Technology Plans of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC Docket No. E-100, Sub 157*, pp. 9-12, October 1, 2018.

antagonism between the *Hope* framework and a grid built around green DERs owned by third parties is summarized in this 2017 Electricity Journal excerpt:[11]

> Under the *Hope* regulatory framework and the capex bias, other resources which might be of value to the grid, such as end user efficiency, are valued derivatively and secondarily to capital's return. DERs can provide various values to the grid, but conflict with the *Hope* regulatory framework in at least two ways. First, DERs reduce the amount of power utilities sell to customers, thus reducing their revenues. Second, DERs displace a utility's capital expenditures. DERs, then, represent the possibility of utility's depreciating itself out of existence while its revenues dwindle.
>
> Because of this contradiction between DERs and the capex bias, the *Hope* regulatory framework which produces it is one of the most entrenched obstacles to the development of a distributed energy grid.

Shareholder value is enhanced, in this capex bias context, by maximizing steel-in-the ground, regardless of whether or not this approach: 1) is the most economically beneficial for customers, or 2) best prepares Duke Energy's grid to accommodate high levels of green DERs.

III. Major Expenditures on Questionable Grid Modernization Projects - A National Trend

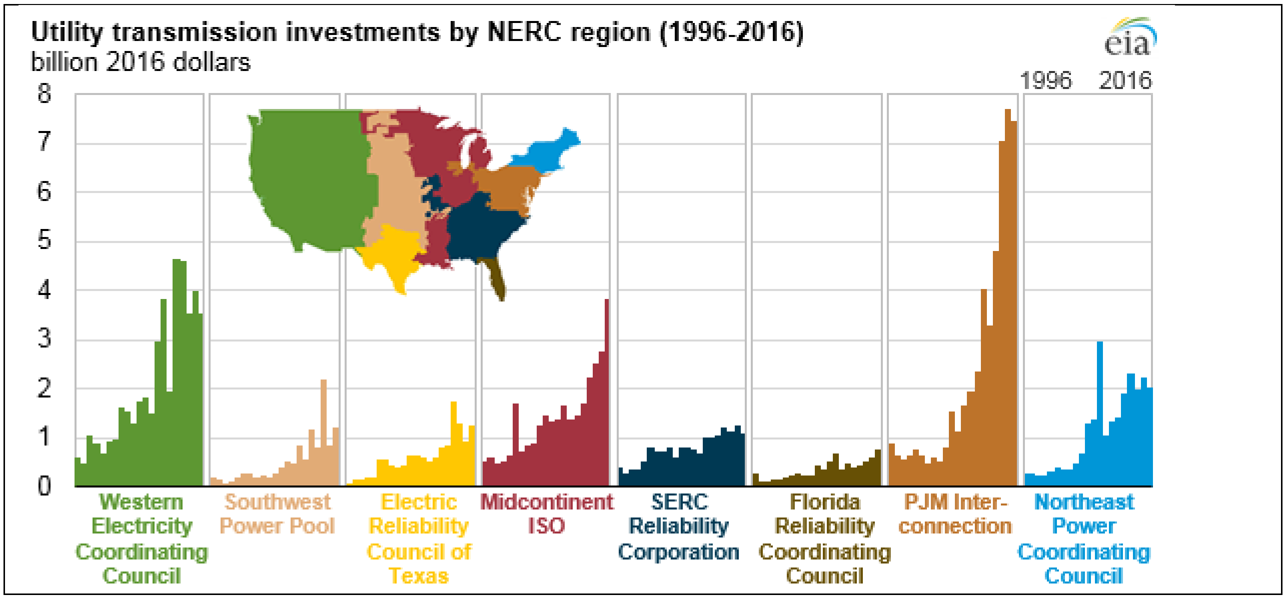
Major expenditures on questionable grid modernization projects is occurring around the country. The genesis of this increase is the 2005 Energy Policy Act and FERC Order 679,[12] which incentivize the building of transmission lines over other alternatives by authorizing higher rates of return for transmission lines. The increase in transmission expenditures is shown in Figure 1.

Figure 1. Trend in U.S. Transmission Line Spending by Region[13]

[11] Ibid, p. 3 of 5.

[12] FERC Order 679, *Promoting Transmission Investment through Pricing Reform*, July 20, 2006: https://www.ferc.gov/whats-new/comm-meet/072006/E-3.pdf.

[13] EIA, *Utilities continue to increase spending on transmission infrastructure*, February 9, 2018. See: https://www.eia.gov/todayinenergy/detail.php?id=34892.



Industry stakeholders around the country are pushing back on the perceived excess of transmission line construction. At a December 2018 MISO meeting on additional transmission expansion, utility representatives questioned whether their customers had had enough of transmission expansion and "*might be better served by a reinforced distribution system than more transmission projects*."[14]

The CEO of American Municipal Power ("AMP"), a public power wholesaler serving many municipal utilities in Ohio, called on federal regulators in December 2017 to provide tighter oversight of supplemental transmission projects.[15] AMP operates in the PJM Regional Transmission Operator service territory, which includes parts of twelve states including northeastern North Carolina. Duke Energy Corporation, via its Duke Energy Ohio affiliate, also operates in PJM.[16]

A supplemental project could be a project to replace existing wood poles with steel and concrete poles for storm-hardening purposes. This type of project might provide additional resilience but is not required to maintain reliable service.[17] Many of the transmission and distribution projects proposed in Duke Energy's Power/Forward Carolinas grid modernization program would fall into this category.

---

[14] RTO Insider, *MISO Stakeholders: New Blueprint Needed for Tx Planning*, December 9, 2018.
[15] M. Gerken – AMP, *To avoid skyrocketing electric transmission costs, FERC scrutiny of 'supplemental' projects is needed*, December 31, 2017. See: https://www.cleveland.com/opinion/index.ssf/2017/12/to_avoid_skyrocketing_electric.html.
[16] K. Rose, *Survey of PJM Transmission Rates and Charges*, prepared for American Municipal Power, September 21, 2018, p. 16 and p. 18. Duke Energy Ohio's transmission revenue requirement increased 73.5 percent from 2013 to 2017.
[17] M. Gerken – AMP, *To avoid skyrocketing electric transmission costs, FERC scrutiny of 'supplemental' projects is needed*, December 31, 2017.

The AMP CEO noted that over $19 billion in supplemental transmission projects had been proposed since the PJM planning process began, with no transparent criteria, assumptions, or models to support decision-making. He also points-out that the high rate-of-return may be the primary driver for the building boom, stating:[18]

> ". . many transmission owners are receiving returns of an astounding 10 to 12 percent. Rates of return should reflect actual market risks and not have the unintended consequence of encouraging building or over-building for the sake of revenue generation."

The controversy over excessive transmission line investment is a national phenomenon, driven by high rates of return, originating with the 2005 Energy Policy Act and FERC Order 679, and relatively little regulatory oversight of many of the transmission lines being proposed.

IV. 2018 Duke Energy IRPs – Capital Expenditure Bias Case Study

Duke Energy's ten-year strategic grid expansion plan, *Power/Forward Carolinas*, and its broader, 15-year *Integrated Resource Plan* is a case study in capex bias. Duke Energy proposes to spend $13 billion on grid upgrades in North Carolina alone. In addition, Duke Energy Corporation plans to spend at least $2.5 billion on the Atlantic Coast Pipeline[19] and Duke Energy plans to spend $10 billion on new gas-fired plants.[20,21] These assets would serve both Carolinas. Meanwhile, it plans to do the minimum in renewable energy development, increasing renewable energy content to only 8 percent of total power supply by 2033.[22]

The major investments proposed by Duke Energy in "grid modernization" infrastructure, presented by the company as necessary to support a green energy future, include undergrounding some distribution lines, building redundant transmission lines to vulnerable communities, transformer and conductor upgrades, cybersecurity, and substation automation.[23] This is in addition to the $1 billion per year that Duke Energy already spends on operations and maintenance of its existing transmission and distribution system in North

---

[18] Ibid.

[19] Duke Energy, *Fourth Quarter Earnings Review and Business Update*, PowerPoint, February 16, 2017, p. 64 (projected investment of $2.4 - 2.6 billion).

[20] Duke Energy Carolinas, *2018 IRP*, September 5, 2018, p. 67, Table 12-H (solar = 2,653 MW, CC = 2,676 MW, CT = 862 MW, CHP = 44 MW, pumped storage = 260 MW, energy storage = 120 MW); Duke Energy Progress, *2018 IRP*, September 5, 2018, p. 69, Table 13-H (solar = 1,631 MW, CC = 3,236 MW, CT = 2,760 MW, CHP = 22 MW, pumped storage = 0 MW, energy storage = 113 MW). Total new DEC and DEP gas-fired resources, 2019-2033, = 9,598 MW.

[21] Duke Energy Carolinas, 2017 FERC Form 1, April 15, 2018, pdf p. 425. Capital cost of 620 MW Dan River combined cycle (CC) = ~$1,000/kW (completed 2012). Assume $1,000/kW is representative of new DEC and DEP CC gas-fired generation, and that CC and CT capital costs, in $/kW, are similar. Therefore cost of new gas-fired generation, 2019-2033 = 9,598 MW x $1,000/kW x 1,000 kW/MW = $9.598 billion.

[22] 2018 DEC IRP, p. 69, Figure 12-F: DEC and DEP Energy Over 15-Year Study Period – Carbon Constrained Base Case, 2033 DEC + DEP Energy Mix.

[23]https://news.duke-energy.com/releases/duke-energy-embarks-on-a-10-year-initiative-to-strengthen-north-carolina-s-energy-grid

Carolina.[24]Duke Energy described the elements of the first three years of its revised Power/Forward program in a November 2018 stakeholder workshop in Raleigh.[25] The undergrounding of power lines accounts for only 3.3 percent of the $2.5 billion budget.[26] Battery storage accounts for about 6.7 percent of the budget.[27] The remaining 90 percent is dedicated to what are effectively status quo upgrades to Duke Energy's existing T&D infrastructure in North Carolina.

V. Duke Energy IRP Strategy – Business-As-Usual Is Restricting Green Energy Innovation

A. Utility-Scale Solar Energy

Duke Energy presumes in its 2018 IRPs that only a modest amount of solar power will be added in North Carolina over the next 15 years, about 4,300 MW, along with about 230 MW of battery storage, and 260 MW of new pumped storage, to be owned and operated by Duke Energy.[28] By way of comparison, about 4,300 MW of solar was installed in North Carolina in the last 4 years.[29] Duke Energy projects relatively little customer net-metered solar and storage will be added through 2033. Duke Energy is presuming the utility-scale solar installation rate will slow substantially over the next 15 years, and that a major expansion of customer-owned solar and storage will not occur.

Duke Energy Corporation awarded 680 MW of solar contracts in July 2018 in the first round of large-scale solar project bidding following the passage of HB 589.[30] Independent solar developers contend that Duke Energy is attempting to extend its monopoly to new projects that would combine battery storage with solar power.[31] These solar industry representatives indicate that onerous conditions imposed by the utility make it impossible for independent developers to offer economically competitive bids for projects that combine storage and solar.[32]

Despite solar industry protests, the NCUC authorized the first round of bidding to move forward and that changes be made to the second round of bids, for approximately 800 MW of capacity, in 2019. Duke Energy has indicated it will be difficult to develop guidelines that compensate

---

[24] John Downey, *Duke Energy: $13 billion spend would create 14,000 jobs over 10 years*, *Charlotte Business Journal*, April 12, 2017, https://www.bizjournals.com/charlotte/news/2017/04/12/duke-energy-plans-13b-in-new-infrastructure.html. "The planned spending would be in addition to the $1 billion Charlotte-based Duke (NYSE:DUK) already spends annually on grid maintenance and upgrades."
[25] Duke Energy, *North Carolina Grid Improvement Plan – Pre-Read Packet for Stakeholder Workshop*, PowerPoint presented in Raleigh, NC, November 8, 2018.
[26] Ibid, p. 97.
[27] Ibid, p. 97.
[28] See footnote 6.
[29] See SEIA North Carolina profile, as of Q3 2018: https://www.seia.org/state-solar-policy/north-carolina-solar.
[30] Charlotte Business Journal, *NC solar developers lose battery storage challenge to Duke Energy*, June 28, 2018.
[31] Ibid.
[32] Ibid.

independent developers for the value that storage can add to solar projects and to the power grid.[33]

B. Distributed Solar and Battery Storage

The DEC and DEP 2018 IRPs both allude to a growing use of distributed solar and battery storage, stating, "*Technical advancements and declining cost trends in distributed energy resources such as battery storage, distributed solar generation and demand-side management initiatives give rise to a future resource portfolio that is comprised of both centralized resources as well as a growing penetration of distributed resources*."[34] However, neither the DEC or DEP IRPs provide any projections on the growth of distributed solar and battery storage from 2019 through 2033.

North Carolina had just under 61 MW of distributed solar at the end of 2017.[35] Only 5 MW of distributed solar were added in 2017. In contrast, the state has about 4,700 MW of solar capacity, and virtually all of it utility-scale solar.[36] The HB 589 rooftop solar rebate program is capped at only 20 MW per year for 5 years, between 2018 and 2022.[37]

In contrast, California installed approximately 2,600 MW of solar in 2017, of which about 1,600 MW was distributed solar and 1,000 MW was utility-scale solar.[38] Most of the solar capacity installed in California in 2017, over 60 percent, was distributed solar. California no longer has a rebate program for distributed solar.

Although the DEC and DEP 2018 IRPs anticipate "*growing penetration of distributed resources*," neither utility quantifies the projected growth of distributed resources between 2019 and 2033. The declining cost trends in distributed solar and battery storage, with or without HB 589 rebates, will lead to high levels of penetration of these resources in North Carolina over the next 15 years. However, there is no way to determine if DEC's or DEP's new resource addition forecasts are reasonable without a concurrent projection of the amount of demand that will be addressed by the growth of distributed solar and battery storage through 2033. This omission needs to be addressed in the DEC and DEP IRPs.

V. Duke Energy – Though Only at Pilot Scale – Is Deploying the Proper IRP Strategy

Duke Energy, despite its current plan to rely largely on upgrades to the existing grid as its future grid optimization strategy, is aware there is a different approach available to assure grid

---

[33] Ibid.
[34] DEC 2018 IRP, p. 9 and DEP 2018 IRP, p. 9.
[35] EIA, *North Carolina Electricity Profile 2017*, full data Table 11, January 8, 2019: https://www.eia.gov/electricity/state/northcarolina/.
[36] See SEIA North Carolina profile, as of Q3 2018: https://www.seia.org/state-solar-policy/north-carolina-solar.
[37] NC Sustainable Energy Association, NC House Bill 589 (accessed January 14, 2019): https://energync.org/hb589/.
[38] See SEIA California profile, as of Q3 2018: https://www.seia.org/state-solar-policy/california-solar.

reliability and manage renewable power generation: large-scale green microgrids where much of the power is generated within the microgrid itself.[39]

DEP applied to the NCUC for authorization to build the Hot Springs microgrid project in October 2018.[40] 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 MW-hours of lithium battery storage. Circuits will be configured to allow Hot Springs to isolate from the grid as needed, known as "islanding," when grid power is unavailable. Hot Springs will operate as a microgrid when islanding. The project is projected by DEP to be online by 2020.[41]

DEP is relying on battery storage in the Hot Springs microgrid – not a gas turbine – to "back up" the 3 MW solar project. Battery storage can do what gas turbines cannot – store and discharge renewable energy. Battery storage projects are also beating gas-fired generation on cost and reliability.[42,43] Industry analysts are currently projecting that battery storage will dominate new peaker applications by the mid-2020s.[44]

Customer-owned solar and battery storage are already cost-effective in North Carolina compared to Duke Energy retail rates, and costs continue to decline.[45] Duke Energy Corporation owns REC Solar, one of the largest commercial solar and battery storage companies in the country.[46,47]

---

[39] Microgrids are generally defined as grids of a limited size, such as a small town, college campus, or even a single building, that can be physically isolated from the larger grid, a condition known as "islanding," and operate independent of the larger grid as necessary. Smaller microgrids can also operate within larger microgrids. A single campus building might be able to island from the campus microgrid, at the same time the campus microgrid can island from the larger utility grid.

[40] Duke Energy Progress, *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.

[41] Ibid, p. 7.

[42] IEEE Spectrum, *Energy storage projects to replace three natural gas power plants in California*, July 17, 2018. See: https://spectrum.ieee.org/energywise/energy/renewables/energy-storage-projects-to-replace-three-natural-gas-power-plants-in-california.

[43] Battery storage is not the only form of storage available. Duke Energy already operates 2,140 MW of readily dispatchable, pumped hydroelectric storage, which is capable of storing solar power for nighttime use and helping solve the intermittency challenge posed by renewables. See: *North Carolina Clean Path 2025: Achieving an Economical Clean Energy Future*, August 2017. p. 19.

[44] Utility Dive, *2019 Storage Outlook: Utility procurement will drive deployments, analysts say*, January 8, 2019: https://www.utilitydive.com/news/2019-storage-outlook-utility-procurement-will-drive-deployments-analysts/545448/. "*Using aggressive assumptions of battery storage cost declines of 10% to 12% every year through 2026, the share of new peaker capacity taken by batteries could rise to as much as 80%.*"

[45] B. Powers, *North Carolina Clean Path 2025*, prepared for NC WARN, August 2017, pp.42-53. See: https://www.ncwarn.org/our-work/clean-path-2025/.

[46] April 15, 2018, *2017 Duke Energy Annual Report and SEC Form 10-K Filing*, p. 14. See: https://www.duke-energy.com/annual-report/_/media/pdfs/our-company/investors/de-annual-reports/2017/2017annualreport.pdf. "(Duke Energy Corporation) Commercial Renewables has expanded its investment portfolio through the addition

REC Solar marketing information indicates its commercial solar and battery storage systems are cost-effective in utility service territories with demand charges above $17 per kilowatt.[48] Duke Energy commercial tariffs have demand charges of as much as $20 per kilowatt.[49]

Municipal utilities and rural cooperatives collectively account for about 25 percent of North Carolina's electricity demand. Municipal utilities have commercial customer monthly demand charges of about $20 per kW.[50] Rural cooperatives have commercial customer monthly demand charges of about $15 to $16 per kW.[51]

REC Solar among many, may not be the least-cost provider. The National Renewable Energy Laboratory indicates commercial customers with demand charges of $15 per kilowatt or more are good candidates for cost-competitive battery storage.[52]

As a result, Duke Energy commercial customers, as well as municipal utility and rural cooperative commercial customers can already benefit economically by installing battery storage.

---

of distributed solar companies and projects, energy storage systems and energy management solutions specifically tailored to commercial businesses. These investments include the 2015 acquisition of a controlling interest in REC Solar Corp., a California-based provider of solar installations for retail, manufacturing, agriculture, technology, government and nonprofit customers across the U.S. and Phoenix Energy Technologies Inc., a California-based provider of enterprise energy management and information software to commercial businesses. In 2017, Duke Energy
acquired the remaining interest in REC Solar."

[47] REC Solar press release, *REC Solar Earns the Title of Third Top Commercial Solar Contractor in the United States*, July 24, 20018, https://recsolar.com/press/rec-solar-top-three-commercial-solar-contractors-2018/: "For two decades, REC Solar has designed, engineered and built projects across the United States, delivering 340 megawatts (MW) of solar solutions across 25 states. The company is the only EPC backed by Duke Energy, the nation's largest utility, giving customers confidence in longevity, service warranties, financial solutions and work quality."

[48] REC Solar brochure, *Energy Storage for Commercial & Utility Customers*, 2017: file:///C:/Users/User/Downloads/REC_Solar_Energy_Storage_Overview%20(1).pdf.

[49] Duke Energy Progress, Large General Service (Time-of-Use) Schedule LGS-TOU-53, effective January 1, 2019, p. 1 (first 5,000 kW of billing demand): https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-nc/g10ncschedulelgstoudep.pdf?la=en. Duke Energy Progress demand charge effective January 1, 2019 for large commercial customers on time-of-use pricing is $20.29 per kW from June through September and $15.15 per kW from October through May.

[50] Telephone communication between A. Fusco, ElectriCities, and B. Powers, Powers Engineering, October 16, 2018.

[51] Wake Electric Membership Corporation, Large General Time-Of-Use Service Schedule "LGS-TOU" (> 50 kW) tariff, on-peak demand charge $ 15.75 per kW. See (p. 21): https://wemc.com/wp-content/uploads/2018/04/RATE-SCHEDULE-FEBRUARY-1-2018.pdf; Randolph Electric Membership Corporation, Schedule LP26TOU Large Power Time-Of-Use Service (> 500 kW), on-peak demand charge $ 15.20 per kW. See (p. 15): https://randolphemc.com/sites/randolphelectric/files/PDF/randrates_0416_final_0.pdf.

[52] NREL, *Identifying Potential Markets for Behind-the-Meter Battery Energy Storage: A Survey of U.S. Demand Charges*, August 24, 2017: https://www.cleanegroup.org/ceg-resources/resource/NREL-demand-charges-storage-market/.

Adding battery storage at the point where power is used will increase reliability for all North Carolina communities, by eliminating dependence on wires. It is a more economical and effective solution than Duke Energy's proposal to: 1) build redundant backup transmission lines to meet vulnerable communities' reliability needs, 2) address transmission congestion caused by solar farms being built in remote parts of the state by building more transmission lines or increasing the capacity of existing lines, and 3) place some distribution lines underground.

Third party solar developers have installed about 4,700 MW of solar in North Carolina,[53] primarily in rural areas in the eastern and southeastern regions of the state. Transmission line congestion is beginning to occur in some of these areas caused by high mid-day solar production. The optimal solution to this congestion is the addition of battery capacity at the solar farm by the developer to reduce daytime peak output and convert the solar resource into a reliable, round-the-clock resource, and not to expand transmission capacity to boost utility capital spending when the issue can be solved more efficiently with battery storage.

VI. Conclusion

Without critical scrutiny of the current conventional capex bias exhibited by Duke Energy in its 2018 IRP filings by NCUC, Duke Energy will continue to oppose third-party developers of solar and battery storage systems, whether they are behind-the-meter in homes and businesses or larger-scale systems across the state.

The outdated *Hope* regulatory framework creates IOU resistance to DERs,[54] as DERs lessen the rationale for adding more grid capex infrastructure. Less investment in new infrastructure threatens the utility's financial growth. In a context where a massive increase in customer-owned solar and storage is the most likely future, a build-out of new conventional infrastructure that is under-utilized, or not used at all, will lead to major stranded costs. In the meantime, the DER that is built would be inefficiently utilized.

[53] See SEIA North Carolina profile, as of Q3 2018: https://www.seia.org/state-solar-policy/north-carolina-solar.
[54] DERs include, but are not limited to, rooftop solar, point-of-use battery storage, energy efficiency, and demand response.