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Key Shortcomings in Duke's North Carolina IRPs

An Issue-by-Issue Analysis: Part 3

Executive Summary

Duke Energy's proposed integrated resource plans (IRPs) for its two operating North Carolina utilities—Duke Energy Carolinas and Duke Energy Progress—outline six possible scenarios for the company to follow in the next 15 years.

Five scenarios entail significant new gas-fired power generation capacity to meet forecasted future power needs across its service territory. A sixth 'no new gas' scenario carries the highest estimated cost—almost as if Duke set it up as a strawman designed to illustrate that turning away from gas would be bad policy. Instead, it shows that the transition can indeed be accomplished without new gas generation, and the question now is just how to go about it to keep costs as low as possible.

In this series, IEEFA examines specific aspects of the Duke proposals to highlight errors we believe policymakers in the state need to consider. Among these are a review of Duke's assumptions concerning natural gas—both for new gas supply and gas-fired generation resources (published in January, this analysis is available here)—which we believe are directly at odds with the company's 2050 net zero carbon pledge; its overly optimistic growth assumptions for energy and peak demand (published in early February and available here); and a look at its approach toward new solar and wind generation capacity.

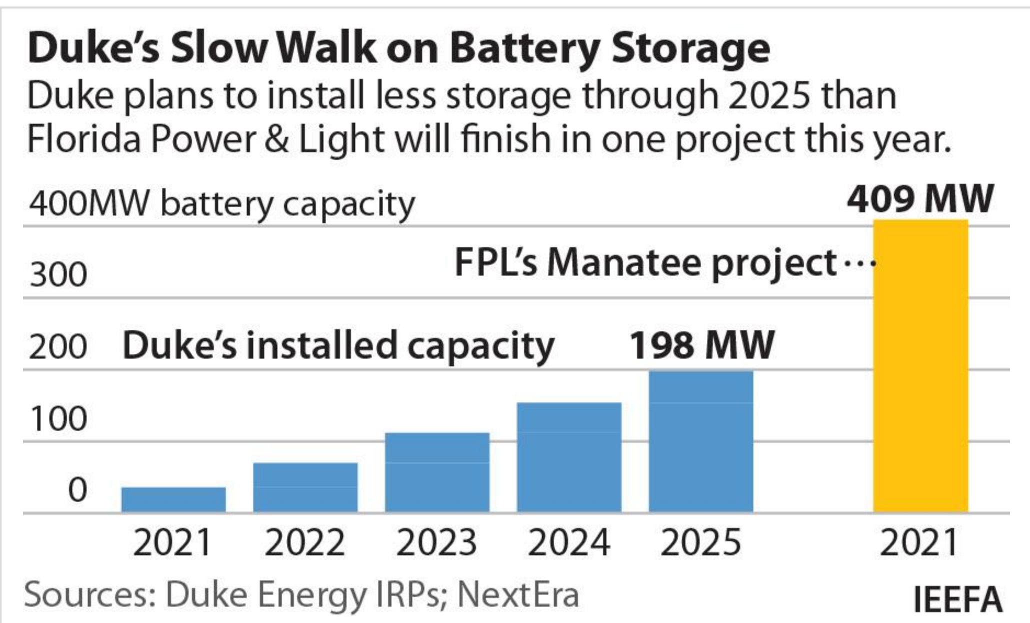
The analysis below focuses on Duke's clear aversion to battery storage technology. IEEFA believes this is a significant error on the company's part. Battery storage options are viable today and being used by utilities of all sizes across the country. Duke's failure to embrace this technology underscores the company's clear preference for conventional generation resources, particularly gas-fired options.

Duke's Dismissal of Battery Storage

Technology's Rapidly Declining Costs Demand Inclusion

One of the most glaring shortcomings in the pending integrated resource plans submitted by Duke Energy's two operating subsidiaries in North and South Carolina is the effective dismissal of the rapidly developing battery storage sector. Despite merging under the Duke Energy umbrella in 2012, the two utilities, Duke Energy Progress and Duke Energy Carolinas, still file separate resource plans with state regulators. It is clear from those plans that they share the same distaste for battery storage.

No standalone battery storage capacity was selected by the capacity expansion model used by the companies in either of their base case analyses (one with no carbon emissions penalty and one imposing a $5 per ton carbon dioxide cost starting in 2025) through 2030, meaning that the companies' modeling deemed them uneconomic. A plan to add 200 megawatts (MW) of battery storage through 2025 is viewed essentially as a pilot project, not a viable commercial application.



The lack of seriousness is apparent in DEC's IRP when it discusses plans for the next five years: "The company **has begun investing** in grid-connected storage systems, with plans for additional multiple grid-connected storage systems. These systems will be dispersed throughout its North and South Carolina service territories . . . These **deployments will allow for a more complete evaluation of potential benefits** (boldface added for emphasis) to the distribution, transmission and generation system."[1]

[1] Duke Energy Carolinas. DEC 2020 IRP. 2020, p. 118.

In other words: We will look into it. Check back in five years.

Duke's approach stands in stark contrast to the wholehearted embrace of battery storage across the rest of the U.S. utility sector. According to the latest forecast from Wood Mackenzie and the Energy Storage Association, **annual** battery storage installations in the U.S. will climb to almost 4,000 MW in 2021 and past 7,400 MW by 2025—pushing total installations during this period to roughly 30,000 MW, of which about 20,000 MW will be in the utility sector.

In a sector developing as rapidly as battery storage, the estimate was out of date almost as soon as it was collected.

Something is clearly amiss if the cost figures for battery storage used by Duke in drafting its IRPs are so high that it will essentially sit out the next five years while other utilities push forward with economically viable projects.

While it is difficult to pin down the specific figures Duke used to calculate its technology costs, the company notes that it relied on data from the U.S. Energy Information Administration's 2020 Annual Energy Outlook. In turn, the 2020 AEO used estimates developed by Sargent & Lundy in 2019, which pegged the capital cost of a 50MW/200 megawatt-hour (MWh) system at $347/kilowatt-hour (kWh).

At best, this estimate represents a 2019 cost, and in a sector developing as rapidly as battery storage, the estimate was out of date almost as soon as it was collected. In contrast, Lazard put the capital cost of a 100MW/400MWh battery storage system at between $164 and $309/kWh in its November 2020 levelized cost of storage report, a range that reflects projects that entered commercial service in 2020.[2] At the low end, the cost is less than half of what was apparently used by Duke—and still significantly less, even at the high end.

Duke does acknowledge elsewhere in its IRPs that the cost of battery storage will decline over time, noting that it has factored in a 49% drop in the coming decade. Using S&L's initial estimate, that would push the cost down to $177/kWh—still higher than some of the projects that Lazard charted in its 2020 analysis.

Elsewhere, in an estimate of the capacity cost of a 10MW/40MWh battery storage unit, Duke says such a project would cost at least $350 per kilowatt-year. It is uncertain from where this figure is drawn but it is also significantly higher than Lazard's 2020 figures, which start at $183/kW-year. And recent prices already appear to be far lower: Nipsco, an Indiana utility, received bids from developers at an average cost of just $134/kW-year for 388MW of battery storage capacity.

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[2] Phone call between the author and Lazard analysts, February 3, 2021.

Beyond the Base Cases

In Duke's other IRP cases, all in some fashion involving a faster transition away from coal- and gas-fired generation, the company does incorporate higher amounts of battery storage. However, it goes out of its way to stress risks, rather than potential.

For example, in its discussion of the IRP case involving no new gas-fired generation, Duke writes: "Notably, the heavier reliance on large-scale battery energy storage in this scenario would require significant additional analysis and study since this technology is emergent with very limited history and limited scale of deployment on power grids worldwide. To provide a sense of scale, at the combined system level it would require approximately 1,100 acres of land, or more than 830 football fields to support the amount of batteries in this portfolio and would represent over six times the amount of large-scale battery storage currently in service in the United States."[3]

While true, the language is highly misleading. The no new gas approach cited by Duke would require an estimated 7,400MW of incremental storage by 2035, but the utility notes that 1,600MW of this total would come from new pumped hydro,[4] reducing the amount of standalone battery storage it needs to 5,800MW—less than 400MW annually over the 15 years. Given Duke's size, this is by no means the daunting amount depicted by Duke's drafting. Worse is the scare tactic about the amount of land the new storage would require. According to the North Carolina Department of Environmental Quality, Duke's four-unit, 2,078MW Marshall steam plant covers 1,370 acres,[5] and the site in Asheville of the company's newest combined cycle gas unit covers roughly 700 acres.[6]

At another point, Duke warns that "the unprecedented levels of storage that are required [in the no new gas scenario] to support significantly higher levels of variable energy resources present increased system risks, given that there is no utility experience for winter peaking utilities in the U.S. or abroad with operational protocols to manage this scale of dependence on short-term energy storage." Similar warnings were commonplace throughout the U.S. utility sector in the early 2010s regarding integrating wind and solar with the transmission grid—warnings that have since been completely disproven.

[3] Duke Energy Carolinas, *op. cit.*, pp. 22-23.
[4] Duke Energy Carolinas, *op. cit.*, p. 94.
[5] North Carolina Department of Environmental Quality. Fact Sheet: Solid Waste Permit Number 1812-Indus-2008. March 2, 2016.
[6] The Citizen Times. Duke Energy officially retires coal units at Lake Julian. January 30, 2020.

Other Approaches

While Duke seemingly is looking for reasons to delay the integration of battery storage, other companies are moving ahead rapidly—and touting the economic benefits of doing so. Florida Power and Light, for example, recently began construction on its 409MW/900MWh Manatee energy storage facility. The company says the facility, which will be charged via an adjacent solar farm, will allow it to retire 1,600MW of aging gas-fired capacity and save ratepayers an estimated $100 million over the life of the project.[7]

Duke seemingly is looking for reasons to delay the integration of battery storage.

Vistra Energy brought an even-larger project online in January in California, beginning commercial operation at its 300MW/1200MWh Moss Landing energy storage facility. The project, which is under contract to Pacific Gas & Electric, was built in a retired gas-fired power plant, reusing equipment and providing ready access to existing transmission infrastructure. It is the largest operating battery storage site in the world, but Vistra already is building a second phase, which will add 100MW/400MWh this year, and is considering more expansion options for the future. The company also just announced plans for a 600MW/2,400MWh energy storage project at its now-closed gas-fired power plant at Morro Bay in California, again giving it the ability to take advantage of the site's existing transmission infrastructure.

Recommendations for Regulators

Before North Carolina regulators sign off on Duke's IRPs, they should require the company to issue a request for proposals for several specific battery storage options. Only by doing this will the commission, and Duke, get current, real-world cost estimates for projects to be built in the next year or two, instead of relying on outdated figures.

Failure to do this risks saddling ratepayers with new, soon-to-be-stranded gas-fired generation capacity, and ignores the compelling economic case that has led other utilities across the U.S. to rapidly add energy storage as a key part of their power infrastructure.

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[7] Energy Storage News. Work begins on 409MW/900MWh Florida battery project to ease natural gas plants into retirement. February 2, 2021.

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An IEEFA analyst and editor, Dennis Wamsted has covered energy and environmental policy and technology issues for 30 years. He is the former editor of The Energy Daily, a Washington, D.C.-based newsletter, and is a graduate of Harvard University.