STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 165

In the Matter of 2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans	)))	**REPLY COMMENTS OF** **TECH CUSTOMERS**

Intervenors Apple Inc., Facebook, Inc., and Google LLC (collectively, "Tech Customers"), by and through counsel, respectfully submit these reply comments pursuant to Rule R8-60(k) regarding the 2020 Integrated Resource Plan ("IRP") for Duke Energy Carolinas, LLC ("DEC").

INTRODUCTION

A review of the initial comments filed in this proceeding reveals clearly that there is a strong consensus on two overarching aspects of this IRP proceeding. First, this IRP proceeding, in terms of timing and substance, is critical both to the environment and the economy. Second, DEC's IRP suffers from serious flaws that require remedy.

This proceeding occurs as North Carolina transitions from traditional generation to renewable energy—a transition to which the federal and state governments, as well as Duke Energy Corporation ("Duke"), are fully committed.[1] The Public Staff has asked the Commission to provide "direction sooner rather than later" on North Carolina's transition plan.[2] The Public Staff is joined by a record number of public commenters, Intervenors and

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[1] *See* N.C. Governor, Exec. Order No. 80 (October 29, 2018); U.S. President, Exec. Order No. 14008 (January 27, 2021); DEC 2020 IRP, at 6.

[2] Public Staff Cmt., at 109 ("It is important that the issue of the necessity for accelerated coal unit retirements and corresponding replacement generation by other resources receive regulatory authority direction sooner rather than later.").

initial comments; even individual state legislators have advocated for a particular IRP portfolio.[3] The Commission itself has noted, in the context of the most recent general rate case, that this IRP proceeding will chart the course for the retirement of coal generation,[4] and Duke has assured its shareholders that the related construction spree will grow its rate base.[5] Everyone—including Duke—grasps the significance of this IRP proceeding.

There is also striking consensus among commenting parties on a number of deficiencies in DEC's 2020 IRP. DEC's IRP concludes that the cheapest option for replacing coal is building a lot of new, costly gas generation. As the initial comments show, DEC's conclusion is far from an unquestionable truth. First and foremost, DEC never considered whether joining a wholesale market, such as a market run by a regional transmission organization, could curtail the need to construct expensive new generation. Second, DEC downplayed the financial benefits of renewable generation by underestimating the risks posed by carbon taxation, stranded assets, and natural gas prices. Third, DEC offered dubious impediments to the alternative options of importing more capacity and building more renewable generation. The significance of DEC's 2020 IRP

[3] Rep. John Autry, et al., *Letter Regarding E-100 Sub 165 2020 Integrated Resource Plans Supporting an Order to Close all Coal-Burning Power Plants in North Carolina by 2030* (Mar. 3, 2021) [docketed on April 8, 2021].

[4] *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice*, Docket No. E-7, Subs 1213, 1214, 1187 (Mar, 31, 2021), at 47.

[5] *See* Duke Energy Corporation, *Edited Transcript: Q3 2020 Duke Energy Corporation Earnings Call* (Nov. 5, 2020) (Duke's "$65 billion to $75 billion capital plan for 2025 through 2029 includes clean energy generation and transmission investments across the Carolinas, Indiana and Florida, as well as an estimate of the distribution investments that will be required to enable renewables, battery storage and other distributed energy generation on our system. Our confidence in the growing rate base over the long term is rooted in these strong capital plans."), *available at* https://desitecoreprod-cd.azureedge.net/_/media/pdfs/our-company/investors/news-and-events/2020/3qresults/3q20-earnings-call-transcript.pdf?la=en&rev=ae12c11f43004ec5a389feedb7c06c6e.

requires the Commission to closely scrutinize these deficiencies and issue an order directing DEC to revise its IRP to cure these shortcomings.

REPLY COMMENTS

I. DEC MUST CONSIDER WHETHER PARTICIPATION IN A WHOLESALE MARKET WOULD BE THE LEAST-COST OPTION.

In their initial comments, Intervenors called on DEC to analyze whether purchasing more wholesale power could save ratepayers money by reducing the need to build new gas generation. Under North Carolina law, DEC is required to find the "least cost" option for providing reliable electric service.[6] In the context of commitments to reducing carbon emissions, the assessment of least cost is more challenging than ever. DEC's IRP, however, reflects a business-as-usual analysis—one that is heavily reliant on the traditional model of utility construction and control—and projects a steady increase in ratepayers' utility bills for the foreseeable future.[7] Yet, it is impossible for DEC to conclude that its business-as-usual approach is the least-cost option for ratepayers when DEC has not analyzed whether other options—such as increased participation in the wholesale market—would be more cost effective.

Wholesale electricity markets, such as those run by regional transmission organizations ("RTO") and independent system operators ("ISO"), are the most common structural form of energy supply in the United States, and they have been proven to reduce ratepayer's utility bills.[8] Before DEC begins the process of raising ratepayers' utility bills

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[6] *See*, *e.g.*, N.C. Gen. Stat. § 62-2(a)(3a).

[7] *See* DEC 2020 IRP, at 17 (presenting six portfolios composed of new generation, each of which will produce, *at a minimum*, an *annual* increase of 1.3% in ratepayers' bills).

[8] *See* Tech Customers Cmt., at 17.

by building more generation, DEC must study whether joining a wholesale market would lower utility bills in North Carolina.

A. A number of Intervenors have called on DEC to analyze the impact of participating in a wholesale market.

In their initial comments, Tech Customers observed that DEC should, at the very least, analyze how DEC's planned participation the Southeastern Energy Market ("SEEM") will impact DEC's plans for future resources.[9] NCSEA and CCEBA make a similar point, noting that, "[a]t a minimum, the Commission should require Duke to assume interconnection support availability from the entire SEEM footprint."[10] Notably, the South Carolina Office of Regulatory Staff ("ORS") also faulted DEC's 2020 IRP for failing to address SEEM in the ORS's review filed with the South Carolina Public Service Commission.[11]

Tech Customers further pointed out that an analysis of SEEM was just the first step in an appropriate review of wholesale-market options—DEC should consider whether structural reforms, such as an RTO or ISO, would produce benefits for ratepayers.[12] Other commenters made similar observations: NCSEA and CCEBA criticized DEC for failing to

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[9] Tech Customers Cmt., at 15. Since the filing of initial comments in this proceeding, the FERC has issued a deficiency letter that raises several questions about SEEM. *See Deficiency Letter and Request for Additional Information from Alabama Power Co., et al.*, Docket Nos. ER21-1118, *et al.* (May 4, 2021) (Doc. Accession No. 20210504-3015).

[10] NCSEA & CCEBA Joint Cmt., at 42.

[11] South Carolina Office of Regulatory Staff, *Review of Duke Energy Carolinas, LLC 2020 Integrated Resource Plan*, Docket No. 2019-224-E (March 4, 2021), at 8, 99–100 [hereinafter "South Carolina ORS Review"] (calling for DEC to provide "information regarding the monetary benefits that have been or could be achieved by implementation of the SEEM"), *available at* https://dms.psc.sc.gov/Attachments/Matter/7a5c3678-6ac1-4f70-84aa-c096effb9990. (The South Carolina ORS Review is an attachment to the Direct Testimony of Anthony Sandonato.)

[12] Tech Customers Cmt., at 13–18.

"incorporate into its IRPs the potential benefits of broader regionalization through structures such as" imbalance markets and RTOs;[13] and Vote Solar identified the same failure by DEC.[14]

B. The General Statutes and Commission rules require an analysis of whether participating in a wholesale market could be the least-cost option for electricity service.

The criticism reflected in the initial comments of NCSEA, CCEBA, Vote Solar, and Tech Customers highlights the dissonance between DEC's IRP and the overall directive in the Public Utilities Act that utility service must be "adequate," "reliable," *and* "*least cost*."[15] The principle of least-cost service is embedded as a bedrock component of North Carolina's regulatory approach; accordingly, it must be a fundamental component of any plan approved by the Commission in this proceeding.

Consistent with these directives, North Carolina policy requires that a utility endeavor through its "energy planning" to "*decrease* utility bills."[16] Further, to achieve reductions in energy costs, the policy of North Carolina is to "promot[e] and coordinat[e] *interstate* . . . public utility service and reliability of public utility energy supply."[17] And to accomplish these objectives, the Commission is empowered to "regulate public utilities generally" and, in particular, to regulate their "operations" and "expansion."[18]

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[13] NCSEA & CCEBA Joint Cmt., at 42.

[14] Vote Solar Cmt., at 9 ("Duke Energy has declined to assess all regional coordination options that could drive direct customer benefits" such as imbalance markets and RTOs.).

[15] N.C. Gen. Stat. § 62-2(a)(3a) (emphasis added).

[16] N.C. Gen. Stat. § 62-2(a)(3a) (emphasis added).

[17] N.C. Gen. Stat. § 62-2(a)(8) (emphasis added).

[18] N.C. Gen. Stat. § 62-2(b).

Specifically, the General Statutes require the Commission to analyze "the long-range needs for expansion of [generation] facilities" so as "to achieve maximum efficiencies" for ratepayers.[19] As part of its analysis, the Commission must consider not only "generating plants" but also "arrangements for pooling power" and "other arrangements with other utilities and energy suppliers."[20] The Commission's analysis should be in consultation with North Carolina's public utilities and also "the utilities commissions . . . of neighboring states."[21]

Pursuant to its statutory duties, the Commission approved Rule R8-60, which commands public utilities to present an IRP, which should be a "comprehensive analysis of *all resource options*" that will provide service "*at least cost*."[22] The Rule then identifies specific topics to be assessed in the IRP, the first of which is purchasing power: public utilities are required to "assess on an on-going basis the potential benefits of soliciting proposals from wholesale suppliers and power marketers to supply it with needed capacity."[23] Later, the Rule reiterates that, in evaluating resource options, the utility must find a resource plan "that offers the *least cost* combination (on a long-term basis) of reliable

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[19] N.C. Gen. Stat. § 62-110.1(c).

[20] N.C. Gen. Stat. § 62-110.1(c).

[21] N.C. Gen. Stat. § 62-110.1(c).

[22] NCUC Rule R8-60(c)(2) (emphasis added).

[23] NCUC Rule R8-60(d); *see also* Order Granting Certificates, Docket No. E-2, Sub 733 (Nov. 2, 1999), at 8 ("The Commission is of the opinion that there continue to be benefits potentially available to electric utilities from *looking to the wholesale market for generation resources*, and that utilities regulated by the Commission *should make every effort* to do so for possible sources of capacity and energy to serve their retail customers. Therefore, the Commission concludes that CP&L shall fully consider the wholesale market for future generation resource additions that will be used in whole or in part to serve retail customers, whether by formal RFP or *other measures that ensure a complete evaluation of the market*." (emphasis added)).

resource options."[24] As part of its evaluation, the utility is required to analyze "the risks associated with *wholesale markets*"[25] and discuss its recent RFPs for wholesale power.[26]

Furthermore, the Regulatory Conditions of the Duke-Progress merger obligate DEC to "pursue *least cost* integrated resource planning" and "determine the appropriate self-built *or purchased power resources* to be used to provide future generating capacity and energy . . . on the basis of the *benefits and costs* of such siting and resources[.]"[27] In other words, DEC promised the Commission that its IRPs would assess the benefits and costs of purchasing wholesale power.

C. Rather than analyze the savings from joining in a wholesale market, DEC's IRP only considered building new generation.

By statute, rule, and condition, DEC is required to conduct a comprehensive analysis of all resource options—including through the purchase of wholesale power—to find the appropriate options that will lead to a least-cost resource plan: that is, a plan that will *decrease* costs for ratepayers, compared to other potential plans. DEC's 2020 IRP, however, presents six options that will *increase* costs for ratepayers. The options also share another characteristic: they presume that coal plants must be replaced by newly built generation assets. DEC never asks the mandated threshold question—whether DEC can avoid building some generation by purchasing from the wholesale market.

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[24] NCUC Rule R8-60(g) (emphasis added).

[25] NCUC Rule R8-60(g) (emphasis added).

[26] NCUC Rule R8-60(i)(4)(ii).

[27] *Order Approving Merger Subject to Regulatory Conditions and Cost of Conduct*, Docket Nos. E-2, Sub 998, E-7, Sub 986 (June 29, 2012) (Regulatory Condition 3.5), *as amended by Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, Docket Nos. E-2, Sub 1095, E-7, Sub 110, G-9, Sub 682 (Sept. 29, 2016).

Rule R8-60 explicitly requires that an IRP analyze "the potential benefits of soliciting proposals from wholesale power suppliers and power marketers" and "the risks associated with wholesale markets."[28] DEC never conducted such an analysis; or, if it did, the analysis is not reflected in its plan. Instead, DEC offered a list of about 180 MW-worth of existing wholesale purchase power contracts[29] and admitted that it has not issued a single RFP for non-renewable wholesale capacity since its last IRP[30] (an IRP in which it likewise admitted it had not solicited any non-renewable wholesale capacity[31]). Given DEC's apparent refusal to consider acquiring capacity through a wholesale market, it is no surprise that DEC's list of "potential supply-side resource options to meet future capacity needs" is composed exclusively of newly built generation.[32]

DEC cannot conduct its IRP based upon the costly premise that ratepayers must pay for DEC to build all new generation. Chapter 62, Rule R8-60, and Regulatory Condition 3.5 require DEC to analyze whether participation in a regional wholesale market would save ratepayers money. DEC's failure to do so cannot be countenanced.

D. There is ample evidence of the benefits of participating in a regional wholesale market.

DEC's failure to analyze participation in a wholesale market is especially glaring in light of the abundance of evidence supporting the potential benefits of regional wholesale markets. Wholesale markets already cover 35 states, serving two-thirds of the

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[28] NCUC Rule 8-60(d), (g).

[29] DEC 2020 IRP, at 368.

[30] DEC 2020 IRP at 123.

[31] *See* DEC 2018 IRP at 79.

[32] DEC 2020 IRP at 149–50.

country's electricity consumers.[33] Here in North Carolina, the Commission has concluded that Dominion North Carolina Power's participation in PJM has benefited ratepayers.[34]

As identified in Tech Customers' initial comments, several studies have demonstrated the benefits of regional wholesale markets. These benefits include balancing supply and demand over a larger footprint, compelling purchases of cheaper wholesale energy during peak demand, and greater deployment of renewables.[35] Studies have forecasted that a Southeastern RTO could provide cumulative cost savings of up to $384 billion by 2040, with *annual* savings ranging from $411 million to $593 million for the North Carolina customers of DEC and Duke Energy Progress.[36]

E. The Commission has the authority to require an analysis of the benefits and costs of DEC's participation in a regional wholesale market.

The IRP proceeding offers a statutory basis for requiring DEC to study participation in a regional wholesale market—particularly in light of the watershed nature of the current proceeding wherein DEC is proposing to transform its generation fleet. Section 62-110.1(c) requires an "analysis" of "other arrangements with other utilities and energy suppliers" that will "achieve maximum efficiencies."[37] It would seem difficult to satisfy this requirement

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[33] Federal Energy Regulatory Commission, *Energy Primer: A Handbook for Energy Market Basics* (April 2020), at 39, 61, *available at* https://www.ferc.gov/sites/default/files/2020-06/energy-primer-2020_0.pdf.

[34] Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, Docket No. E-22, Sub 532 (Dec. 12, 2016), at 144.

[35] *See* Tech Customers Cmt., 16–17 & nn.42–46.

[36] *See* Tech Customers Cmt., 17 & n.47 (citing Vibrant Clean Energy, *Summary Report: Economic and Clean Energy Benefits of Establishing a Southeast U.S. Competitive Wholesale Electricity Market* (Aug. 2020), at 1; The Brattle Group, *Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers* (Feb. 2019), at 8).

[37] N.C. Gen. Stat. § 62-110.1(c).

without an adequate assessment of a regional wholesale market, such as an imbalance market or RTO, that is widely accepted to produce cost savings. Thus, the Commission is well within its statutory authority to order DEC to undertake such an analysis.

In addition to the specific authority in Section 62-110.1(c), the Commission has "general power and authority to supervise and control" public utilities "as may be necessary to carry out the laws," as well as "all such other powers . . . as may be necessary or incident to the discharge of [the Commission's] duties."[38] These general powers further undergird the Commission's authority to require a study of a regional wholesale market—especially in light of North Carolina's statutory policies of "least cost" energy planning[39] and "promoting and coordinating interstate . . . public utility service and reliability of . . . energy supply."[40]

Finally, under Section 62-42, if the Commission finds, upon notice and a hearing, that an act "is necessary to secure reasonably adequate service" and "serve[s] the public convenience and necessity," the Commission has the authority to enter an order directing that necessary "changes . . . be made" within a prescribed time period.[41] An inadequately considered resource plan that requires the construction and then the early retirement of expensive new generation is not only unnecessarily expensive, it arguably does not result

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[38] N.C. Gen. Stat. § 62-30; *see also* N.C. Gen. Stat. § 62-2(b).

[39] N.C. Gen. Stat. § 62-2(a)(3a).

[40] N.C. Gen. Stat. § 62-2(a)(8).

[41] N.C. Gen. Stat. § 62-42(a)(5); *see also Order Regarding Jurisdiction*, Docket No. E-100, Sub 85A (July 10, 2002), at 6 ("G.S. 62-42 authorizes the Commission to order 'any other act . . . necessary to secure reasonably adequate service or facilities and reasonably and adequately to serve the public convenience and necessity'; this statute is not limited to ordering service repairs or improvements[.]"), *aff'd on other grounds*, *State ex rel. Utils. Comm'n v. Carolina Power & Light Co.*, 359 N.C. 516, 614 S.E.2d 281 (2005).

in "reasonably adequate" service. The Commission could consider instituting a proceeding to determine if participation in a regional wholesale market would produce cost savings and, if the study proves so, require the utilities to make necessary changes.

Virginia has already embraced a regional wholesale market, and South Carolina—the other state in which DEC operates—is currently considering whether to follow suit.[42] DEC has already sought approval for SEEM, which is a stepping stone towards participation in wholesale energy markets. North Carolina should study whether it should join our neighbors in a wholesale power market. This analysis should be an integral component of DEC's planning effort and this Commission's consideration of that effort.

II. DEC MUST PROPERLY ACCOUNT FOR THE FINANCIAL BENEFITS OF RENEWABLE GENERATION.

DEC's IRP deems the construction of capital-intensive natural gas generation to be the cheapest option for replacing coal. DEC's plan, however, poses sizable financial risk to ratepayers due to gas generation's exposure to the possibilities of carbon taxation, such assets becoming stranded, and future restrictions on fuel supply. Renewable generation avoids these financial risks. DEC's failure to properly account for gas generation's financial risks results in the failure of its IRP to identify the least-cost energy plan.

A. DEC's modeling must better account for the risk of carbon taxation.

In its initial comments, Tech Customers warned that DEC's assumed carbon taxation was too low and that underestimating a future carbon policy would be very costly

[42] *See* Act No. 187 of 2020 Session of South Carolina Legislature (H.B. 4940).

to ratepayers.[43] Voter Solar echoed this objection.[44] The Public Staff likewise was concerned that "failing to properly account for this uncertainty [regarding future carbon taxation] can . . . create future risk of higher rates" and called on DEC to "account for and consider[] . . . the risks" of a future carbon tax.[45] The Public Staff highlighted that if DEC was inaccurate in its carbon-tax prediction, it could cost ratepayers billions of dollars.[46] NCSEA, et al. astutely noted that a true least-cost analysis would assign a cost to the risk posed by the range of possible future carbon costs.[47] In view of these comments, Tech Customers ask the Commission to direct DEC to use a weighted average of the various carbon-tax proposals that are identified in its IRP.[48]

B. DEC must model the risks of stranded assets.

Tech Customers faulted DEC for failing to account for the financial implications of the risk of stranded assets.[49] For example, DEC defends its natural-gas buildout by claiming that its modeling showed that it is economical to retire gas plants after only 25 years

[43] Tech Customers Cmt., at 4–5.

[44] Vote Solar Cmt., at 8.

[45] Public Staff Cmt., at 21.

[46] *See* Public Staff Cmt., at 164.

[47] NCSEA, CCEBA, SACE, Sierra Club and Natural Resources Defense Council Cmt., at 8 [Hereinafter "NCSEA, et al. Cmt.,"] (arguing that statutes and rules "certainly cannot intend that the resource portfolio that should be labeled as 'least cost' is the one that has the absolute lowest cost, without regard the accuracy of its underlying assumptions or the risk that those assumptions present to ratepayers."); *accord* Public Staff Cmt., at 162–64 ("It is the Public Staff's position that 'least cost' [as used in N.C. Gen. Stat. § 62-2(3a)] must consider not only the factors that are known and present at the time of the IRP, but also potential future charges to the electricity industry, combined with their likelihood of occurrence and potential risk factors . . . . The recommendation of a 'least cost' plan has to, in part, consider the uncertainty around whether there will be carbon pricing in the future.").

[48] *See* DEC 2020 IRP, at 152–53.

[49] Tech Customers Cmt., at 6.

(instead of their usual lifespan of 40 years).[50] In order for DEC to achieve its own 2050 net-zero-emissions goal, however, some of DEC's future gas plants could have lifespans as short as 15 years[51]—a full decade shorter than what DEC modeled. Vote Solar, NC WARN, and CBD joined with Tech Customers in demanding that DEC account for the full risk of ratepayers having to pay for future stranded gas plants.[52]

The Public Staff likewise expressed concern that DEC's "anticipated buildout of natural gas" could result in the "forced retirement of natural gas assets," and ratepayers should not pay simultaneously for abandoned plants and their replacements.[53] The Public Staff cautioned that DEC's current gas-dependent pathway "could leave North Carolina ratepayers worse off over the long term if carbon policy is implemented after building new carbon emitting generation resources."[54]

C. DEC's model is based on unreliable assumptions about the availability of natural gas.

Tech Customers objected to DEC's assumption that it would have ample access to inexpensive natural gas as part of its future buildout of gas generation.[55] The Public Staff

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[50] *See* Tech Customers Cmt., at 6 (citing DEC 2020 IRP, at 136).

[51] *See* DEC 2020 IRP, at 200 (Table A-20 shows DEC's Base Case requiring new combustion turbine plants to be built in 2030, 2031, and 2035, as well as a new combined cycle plant to be built in 2035).

[52] Vote Solar Cmt., at 9; NC WARN & CBD Joint. Cmt., at 1–2.

[53] Public Staff Cmt., at 12.

[54] Public Staff Cmt., at 21.

[55] Tech Customers Cmt., at 7.

was also concerned with DEC's forecast of natural gas prices, especially DEC's dependence on "as-yet unavailable capacity" to supply its future gas needs.[56]

NCSEA and CCEBA highlighted two particular errors underlying DEC's gas-price analysis: First, "Duke . . . simply assumes that firm capacity to deliver . . . gas to all its new CC units will be available from 'new and upgraded' capacity at a constant price."[57] Second, "Duke does not plan on contracting for firm natural gas delivery for its CT units, despite major natural gas additions in some scenarios that will be utilized during cold winter mornings at the exact same time when the natural gas distribution system will be under stress from building heat loads[.]"[58]

The Public Staff, NCSEA, and CCEBA joined with the Tech Customers in reproving DEC for its unrealistic assumptions as to future natural gas prices.[59] In addition, the SC ORS raised a similar objection to DEC's gas prices in the South Carolina proceeding.[60] The Tech Customers join the Public Staff in expecting DEC to "re-evaluate its prediction that additional interstate pipeline capacity will be available" and develop a portfolio that "includes natural gas import restrictions."[61] Although the Public Staff is content to wait until DEC's next IRP for this correction,[62] Tech Customers, NCSEA, and CEBBA ask that this error be remedied now.[63]

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[56] Public Staff Cmt., at 13.

[57] NCSEA & CCEBA Joint Cmt., at 12.

[58] NCSEA & CCEBA Joint Cmt., at 12.

[59] Public Staff Cmt., at 18-19, 94; NCSEA & CCEBA Joint Cmt., at 4.

[60] South Carolina ORS Review at 5, 49–50.

[61] Public Staff Cmt., at 94.

[62] *See* Public Staff Cmt., at 94.

[63] *See* NCSEA & CCEBA Joint Cmt., at 46.

III. DEC MUST REEVALUATE THE PURPORTED BARRIERS TO REPLACING COAL PLANTS WITH NON-GAS ALTERNATIVES.

DEC claims that the least-expensive replacement option for coal plants is the construction of expensive natural gas plants. Although other options exist—such as importing more capacity or building large-scale renewable generation—DEC has identified barriers it believes would forestall further consideration of these alternatives. One such barrier is the enormous transmission costs that DEC assigns to importation and renewables. Another barrier is DEC's insistence that it must build more gas plants to maintain sufficient capacity reserves. The Public Staff and Intervenors, however, have shown that these purported barriers do not withstand scrutiny.

A. DEC offers unsupported estimates of enormous transmission costs associated with importation and renewables.

In is IRP, DEC presented multi-billion-dollar barriers to importing more capacity and integrating large-scale renewables.[64] Tech Customers criticized DEC's IRP for claiming billions of dollars in future transmission costs for importation and renewables, yet failing to support such huge figures.[65] Tech Customers were not alone in voicing this

[64] *See* DEC 2020 IRP, at 58–59 ($4 billion and $5 billion in transmission upgrades to import 5,000 MW of capacity; $8 billion to $10 billion to import 10,000 MW); *id.*, at 16 ($7.5 billion and $8.9 billion in transmission investments to integrate large-scale renewables in the high-wind and no-new-gas scenarios, respectively).

[65] Tech Customers Cmt., 8–9.

criticism. The Public Staff, the Attorney General, NCSEA, and CCEBA also criticized DEC for conducting only a cursory analysis of future transmission investments.[66]

The dearth of analysis surrounding DEC's transmission investments is especially surprising in light of, as the Public Staff noted, transmission investments "taking on greater significance than seen in previous IRPs."[67] The Public Staff further noted that transmission investments will be needed for coal retirement, energy storage, importation, and renewables;[68] and a large transmission expenditure can often operate as "a barrier" to developing such projects.[69] Indeed, the Attorney General is troubled that DEC's large transmission estimates might function as an unwarranted barrier to increasing capacity importation: "Duke provides some estimates of what it would cost to install upgrades to increase neighbor assistance through its transmission infrastructure. . . . The implication here is that these upgrades are too expensive and not worth pursuing."[70]

It appears DEC selectively incorporated transmission estimates into its 2020 IRP. DEC identified huge transmission estimates for increased importation and renewables.[71]

[66] *See* Public Staff Cmt., at 143 ("The Utilities have also presented the possible needs for increased transmission import capability, but did not base their projection of costs on any formal study, evaluation, or analysis."); NCSEA & CCEBA Joint Cmt., at 42-43 ("Duke did not provide enough detail about its transmission planning assumptions or costs."); Attorney General Cmt., at 20 ("Duke fails to examine how the benefits of increased imports might make an even expensive upgrade worth the investment.").

[67] Public Staff Cmt., at 137.

[68] Public Staff Cmt., at 137.

[69] Public Staff Cmt., at 145.

[70] Attorney General Cmt., at 20 (footnote omitted).

[71] *See* DEC 2020 IRP, at 58–59 ($4 billion to $5 billion in transmission upgrades to import 5,000 MW of capacity; $8 billion to $10 billion to import 10,000 MW); *id.*, at 57 ($1.7 billion and $1.9 billion in transmission upgrades to integrate large-scale renewables as in the 70%-carbon-reduction scenario and no-new-gas scenario, respectively).

Yet, the Public Staff pointed out that DEC's model failed to account for certain transmission costs associated with its modeled portfolios, which could "potentially yield[] a suboptimal selection of future resources."[72] The Public Staff called on DEC to provide information about additional import capacity needed to support its modeled portfolios, including the associated transmission costs.[73] NCSEA and CCEBA similarly called for "[m]ore rigorous analysis and assumptions of projects and costs to support future needs" and for DEC to consider "economies of scale with bulk transmission upgrades."[74]

The demands for more transmission details are well grounded. Tech Customers join the Public Staff in having confidence that DEC can "improve the [transmission] planning process without becoming too granular and time intensive."[75] Indeed, DEC already separately provides some information about future transmission investments. DEC publishes an annual interconnection report that provides a list of near-term generation projects.[76] DEC has also identified areas with existing constraints on transmission that might need upgrades.[77] Furthermore, DEC makes forecasts of transmission investments in other contexts, such as the 2020-2030 NCTPC Transmission Plan, which includes a table of major transmission and generation projects through 2030 as well as cost estimates for

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[72] Public Staff Cmt., at 145.

[73] Public Staff Cmt., at 16.

[74] NCSEA & CCEBA Joint Cmt., at 43.

[75] Public Staff Cmt., at 145.

[76] *See* Duke Energy Carolinas, LLC, *Small Generator Interconnection Consolidated Annual Report*, Docket No. E-100, Sub 113B (March 31, 2021).

[77] DEC-DEP Generation Interconnection Requirements and Location Guidance (Aug. 5, 2019), *available at* https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/DEP-DEC_Generator_Interconnection_Requirements_and_Locational_Guidance_8-5-2019_FINAL.pdf .

the transmission projects.[78] DEC should be able to supplement this existing information to generate assumptions that would allow for more comprehensive estimates of the costs of potential future transmission needs.

DEC claims its modeling proves that gas generation is the least-cost option for replacing coal, and DEC cautions that any alternatives, such as importation and renewables, would require cost-prohibitive transmission investments. But DEC's model, as the Public Staff points out, selected gas generation without accounting for all of its associated transmission costs;[79] and DEC's estimates of transmission costs for non-gas options are simply unreliable.[80] DEC must properly estimate and account for transmission costs before the Commission can place any reliance on DEC's conclusion that new gas generation is the least-cost option for replacing coal.

B. DEC is overstating the need to build new gas generation to maintain adequate capacity reserves.

The Public Staff and other Intervenors joined Tech Customers in identifying numerous errors in the amount of capacity DEC claims it needs to adequately meet future peak demand.

First, Tech Customers asked whether DEC's determination to maintain a firm minimum reserve margin was unwarranted and put ratepayers at risk of large investments

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78 NCTPC, *Report on the NCTPC 2020-2030 Collaborative Transmission Plan* (Jan. 15, 2021), at 16–19, 33–37, *available at* https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2020-2030_NCTPC_Report_01_15_2021_FINAL_REPORT.pdf.

79 *See* Public Staff Cmt., at 145.

80 *See* Tech Customers Cmt., at 9 (explaining how DEC's estimates of transmission costs do not even qualify as "Class level 5" estimates).

in unneeded generation.[81] The Attorney General likewise observed that "if the reserve margin were less than 17%, it might be possible to retire additional coal assets without replacement generation."[82] The Commission raised the same question about DEC's inflexible reserve margin in its last IRP order.[83]

Second, Tech Customers further questioned DEC's commitment to building large gas plants to maintain its 17% reserve margin, rather than constructing incremental renewable generation as needed.[84] The Public Staff also noted that "the development and construction of solar (and other renewables) can be done in a piecemeal approach, rather than a 'lumpy' approach, as is the case with traditional generation (fossil and nuclear)."[85] The advantage to ratepayers is that renewables "allow utilities to build only what they need to fulfill their capacity needs."[86]

Third, the Public Staff, the Attorney General, NC WARN, and CBD faulted DEC for not fully acknowledging its ability to import capacity to satisfy peak demand. The Public Staff said it was noteworthy that DEC's IRP "does not allow imports from . . . neighboring balancing authorities to meet capacity or energy needs,"[87] and the Attorney General advocated that an "increase [in] neighbor assistance" could avoid the construction of expensive generation.[88] NC WARN and CBD cautioned that DEC's table of lowest

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[81] Tech Customers Cmt., at 10–12.

[82] Attorney General Cmt., at 19.

[83] 2019 IRP Update Order, at 11.

[84] Tech Customers Cmt., at 10–12.

[85] Public Staff Cmt., at 114.

[86] Public Staff Cmt., at 114.

[87] Public Staff Cmt., at 143.

[88] Attorney General Cmt., at 4.

operating reserves was misleading, as the figures excluded DEC's purchases of non-firm imports.[89] NC WARN and CBD added that, in past testimony about extreme weather, DEC assured the Commission that it was not close to shedding load because it still had access to importable energy.[90] DEC should incorporate its access to non-firm imports in its reserve calculations.

A large chorus of parties called on DEC to acknowledge its ability to use demand-side management ("DSM") to reduce winter peak demand. The Public Staff opened by asking that DEC's forecast of DSM resources include expected load reductions.[91] The Attorney General, NCSEA, CCEBA, NC WARN, CBD, SACE, Sierra Club, and Natural Defense Council criticized DEC for failing to account for the ability of DSM resources to help meet peak winter demand.[92] These objections are well grounded in light of Section 62-155(b)'s mandate for demand-curtailment plans;[93] DEC's refusal to incorporate DSM resources into its capacity planning undermines one of the key benefits of demand curtailment.

Intervenors also exposed flaws in DEC's forecast of its winter peak demand. NCSEA, CCEBA, SACE, Sierra Club, and National Defense Council all objected to DEC's use of a faulty methodology to forecast winter peak demand. Because DEC lacked historical load data for extreme cold temperatures, DEC extrapolated such demand by using

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[89] NC WARN & CBD Joint Cmt., at 8 (citing DEC 2020 IRP, at n.10).

[90] NC WARN & CBD Joint Cmt., at 9–10.

[91] Public Staff Cmt., at 18.

[92] Attorney General Cmt., at 25–26; NCSEA & CCEBA Joint Cmt., at 28–31; NC WARN & CBD Joint Cmt., at 13; SACE, Sierra Club, and Natural Defense Council Joint Cmt., at 7–8 [hereinafter "SACE et al. Joint Cmt."].

[93] N.C. Gen. Stat. § 62-155(b).

a linear regression model.[94] But this model ignored that, at extreme temperatures, the heating load reaches saturation—meaning that demand does not continue to increase linearly at extreme temperatures.[95] As a result, DEC's linear modeling overestimated demand for its winter peaks.[96] In South Carolina, the SC ORS found that correcting this modeling error would have "a *significant impact* on the level of required winter reserves."[97] The Public Staff identified this issue and called on DEC to "better quantify[] the response of customers to low temperatures."[98]

This IRP is not the first time DEC has overstated its needs for future capacity. As the Public Staff pointed out, for the past six years DEC has, on average, overestimated its winter peak demand by over 1,200 MW.[99] Thus, unless DEC improves its historical batting average, then DEC will ask ratepayers to pay for ***three*** 400 MW combustion turbines to handle peak demand *that will never occur*.[100] The Commission can and should require DEC to address the problems identified by the Public Staff and Intervenors so as to properly size its reserve capacity needs.

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[94] NCSEA & CCEBA Joint Cmt., at 4, 26; SACE et al. Joint Cmt., at 13–17.

[95] NCSEA & CCEBA Joint Cmt., at 4, 26; SACE et al. Joint Cmt., at 13–17.

[96] NCSEA & CCEBA Joint Cmt., at 4, 26; SACE et al. Joint Cmt., at 13–17.

[97] South Carolina ORS Review, at 4, 34-38 (emphasis added). To estimate the impact of DEC having miscalculated the load demand on extremely cold days, the SC ORS removed some instances of the coldest temperatures from DEC's data set, *see id.* at 36, and found that DEC's necessary reserve margin dropped from 16% all the way down to only 13.5%, *see id.* at 37 (Table 8).

[98] Public Staff Cmt., at 17.

[99] Public Staff Cmt. at 44-45.

[100] *See* DEC 2020 IRP, at 100–04 (DEC currently plans to build a 402 MW combustion turbine in 2025, a 457 MW combustion turbine in 2029, and a 457 MW combustion turbines 2030).

CONCLUSION

Tech Customers respectfully request that the Commission direct DEC to submit a revised plan that:

1. Considers whether enhanced participation in wholesale markets would be the least-cost option by incorporating scenarios that account for the impact on DEC's plan for future resources of DEC's participation (a) in SEEM and (b) in restructured wholesale markets.
2. Accounts for the financial benefits of increased usage of renewable generation.
3. Provides an accurate calculation of the potential financial costs associated with an increase in renewable generation and with the transmission upgrades necessary to increase the importation of capacity.

Respectfully submitted this the 28th day of May, 2021.

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CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing Initial Comments of Tech Customers was served on all parties or their counsel of record in this docket via electronic mail, this the 28th day of May, 2021.

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By: ____________________________
Craig D. Schauer