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NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

July 26, 2019

Ms. Janice Fulmore, Deputy Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-100, Sub 157 – 2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans

Dear Ms. Fulmore:

Attached for filing is the Proposed Order of the Public Staff in the above-referenced docket.

By copy of this letter, I am forwarding a copy to all parties of record by electronic delivery.

Sincerely,

Electronically submitted
s/ Lucy E. Edmondson
Staff Attorney
lucy.edmondson@psncuc.nc.gov

LEE/cla

Attachment

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 157

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans	)))	ORDER ACCEPTING INTEGRATED RESOURCE PLANS AND ACCEPTING REPS COMPLIANCE PLANS

HEARD: Monday, February 4, 2019, at 7:00 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, [1] Lyons Gray, Daniel G. Clodfelter, and Charlotte A. Mitchell.

APPEARANCES:

For Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC (Duke):

Robert W. Kaylor, Law Office of Robert W. Kaylor, PA, 353 East Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina:

E. Brett Breitschwerdt, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For North Carolina Sustainable Energy Association:

Benjamin Smith, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

[1] Chairman Edward S. Finley, Jr., resigned from the Commission effective June 1, 2019, and the terms of Commissioners Jerry C. Dockham and James G. Patterson ended effective June 30, 2019.

For NC WARN, INC.:

Kristen Wills, Post Office Box 61051, Durham, North Carolina 27715-105

For the Using and Consuming Public:

Teresa Townsend, Special Deputy Attorney General, Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27603

Dianna Downey, Heather Fennell, Bob Gillam, Staff Attorneys, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. IRP considers demand-side alternatives, including conservation, efficiency, and load management, as well as supply-side alternatives in the selection of resource options. Commission Rule R8-60 defines an overall framework within which the IRP process takes place in North Carolina. Analysis of the long-range need for future electric generating capacity pursuant to N.C. Gen. Stat. § 62-110.1 is included in the Rule as a part of the IRP process.

General Statute § 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. The Commission's analysis should include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal

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Energy Regulatory Commission (FERC). Further, N.C. Gen. Stat. § 62-110.1 requires the Commission to consider this analysis in acting upon any petition for the issuance of a certificate for public convenience and necessity for construction of a generating facility. In addition, N.C. Gen. Stat. § 62-110.1 requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of its: 1) analysis and plan; (2) progress to date in carrying out such plan; and (3) program for the ensuing year in connection with such plan. N.C. Gen. Stat. § 62-15(d) requires the Public Staff to assist the Commission in making its analysis and plan pursuant to N.C. Gen. Stat. § 62-110.1.

General Statute 62-2(a)(3a) declares it a policy of the State to:

> assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills....

Session Law (S.L.) 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended N.C. Gen. Stat. § 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the

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resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which N.C. Gen. Stat. § 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval."[2]

Senate Bill 3 also defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function."[3] Energy Efficiency measures do not include DSM.

To meet the requirements of N.C. Gen. Stat. § 62-110.1 and N.C. Gen. Stat. § 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires that each utility, to the extent that

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[2] N.C. Gen. Stat. § 62-133.9(c).

[3] N.C. Gen. Stat. §§ 62-133.8(a)(2) and (4).

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it is responsible for procurement of any or all of its individual power supply resources,[4] furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in Rule R8-60. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report.

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports, and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

[4] During the 2013 Session, the General Assembly enacted S.L. 2013-187 (House Bill 223), which exempted the EMCs from the requirements of N.C. Gen. Stat. § 62-110.1(c) and N.C. Gen. Stat. § 62-42, effective July 1, 2013. As a result, EMCs are no longer subject to the requirements of Rule R8-60 and are no longer required to submit IRPs to the Commission for review.

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2018 BIENNIAL REPORTS

This Order addresses the 2018 biennial reports (2018 IRPs) filed in Docket No. E-100, Sub 157, by Duke Energy Progress, LLC (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion Energy North Carolina (DENC) (collectively, the investor-owned utilities, utilities or IOUs). In addition, this Order also addresses the REPS compliance plans filed by the IOUs.

The following parties have been allowed to intervene in this docket: North Carolina Sustainable Energy Association (NCSEA); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); North Carolina Waste Awareness and Reduction Network (NC WARN); North Carolina Clean Energy Business Alliance (NCCEBA); Carolina Utility Customers Association, Inc. (CUCA); Environmental Defense Fund (EDF); jointly, Southern Alliance for Clean Energy, the Sierra Club, and the Natural Resources Defense Council (SACE, the Sierra Club, and NRDC); Ecoplexus, Inc. (Ecoplexus); and Broad River Energy, LLC (Broad River). The Public Staff's intervention is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e). The Attorney General's intervention is recognized pursuant to N.C. Gen. Stat. § 62-20.

PROCEDURAL HISTORY

On May 1, 2018, DENC filed its 2018 biennial IRP report and REPS compliance plan. DEC and DEP (collectively, Duke) filed their 2018 biennial IRP reports and REPS compliance plans on September 5, 2018.

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On September 27, 2018, the Commission issued an Order Scheduling Public Hearing on 2018 IRP Plans and Related 2018 REPS Compliance Plans. That Order set the public witness hearing for 7:00 p.m. on February 4, 2019, in Raleigh.

On January 17, 2019, NCSEA filed a motion requesting that the date for initial comments on Duke's IRPs be extended to February 15, 2019, and that the date for reply comments be extended to April 16, 2019.

On January 22, 2019, the Public Staff and DENC filed a joint motion for extension of time for filing of initial comments by the Public Staff and other intervenors and reply comments of DENC and other parties on DENC's IRP report and REPS compliance plan. The Public Staff and DENC explained that the State Corporation Commission of Virginia (VSCC) had ordered Dominion Energy Virginia, the operating name of Virginia Electric and Power Company in Virginia, to make certain corrections to its 2018 IRP and to refile the corrected version within 90 days of the VSCC Order. They indicated that DENC intended to file its corrected IRP in North Carolina at the same time it filed the corrected IRP in Virginia, due March 7, 2019. These movants requested that the Commission extend the time for parties to file initial comments on DENC's 2018 IRP to 60 days after DENC files its corrected 2018 IRP, and to extend the due date for parties to file reply comments to 60 days after the due date of initial comments.

On January 24, 2019, the Commission issued an Order to extend the date for parties to file initial comments on DENC's IRP to 60 days after the filing of

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DENC's corrected IRP, and to extend the due date for parties to file reply comments to 60 days after the due date of initial comments.

On January 24, 2019, the Commission issued an Order to extend the date for parties to file initial comments on Duke's IRPs to February 15, 2019, and to extend the date for reply comments to April 16, 2019, and in addition, to close the time period for submitting new discovery requests to Duke on its IRPs.

On February 4, 2019, the public witness hearing was held in Raleigh, as scheduled.

On February 7, 2019, the Public Staff filed a second motion for extension of time for the filing of comments on Duke's IRPs to March 7, 2019.

On February 8, 2019, the Commission issued an Order extending the date for parties to file initial comments on Duke's IRPs to March 7, 2019, and the date for parties to file reply comments to May 6, 2019.

On March 7, 2019, initial comments were filed by the Public Staff, NCSEA, the Attorney General's Office, and jointly by SACE, the Sierra Club and NRDC, on Duke's IRPs and REPS compliance plans.

On March 7, 2019, DENC filed an update to its IRP to comply with the VSCC Order (Compliance Filing). The 30-page Compliance Filing included updated cost estimates, created a new alternative plan, and made other changes in an effort to comply with the VSCC Order.

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On April 29, 2019, Duke filed a filed a motion for a two-week extension of time through and including May 20, 2019, for parties to file their reply comments to Duke's IRPs.

On May 1, 2019, the Commission issued an Order extending the date for parties to file reply comments on Duke's IRPs to May 20, 2019.

On May 6, 2019, the Public Staff filed comments on DENC's IRP and REPS compliance plan.

On May 20, 2019, reply comments were filed by NC WARN to Duke's IRPs.

On May 20, 2019, reply comments were filed by Duke to the comments filed by the Public Staff, the Attorney General's Office, EDF, NCSEA, the joint comments of SACE, the Sierra Club and NRDC, and NC WARN.

On May 20, 2019, the Attorney General's Office filed reply comments on Duke's IRPs and REPS compliance plans.

On June 12, 2019, the Commission issued an Order requiring filing of proposed orders.

On July 5, 2019, DENC filed reply comments in response to the May 6, 2019, comments of the Public Staff.

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PUBLIC HEARING

Pursuant to N.C. Gen. Stat. § 62-110.1(c) the Commission held a public hearing in Raleigh on Monday, February 4, 2019, at 7:00 p.m., where 49 public witnesses spoke. In summary, the testimonies of the public witnesses focused on the need to encourage energy efficiency and clean renewable resources, such as solar and wind. A few of the witnesses commented on the value of integrating batteries, and other storage technologies, with the utilities' distributed resources. In addition, the witnesses encouraged the Commission to promote an economy and energy future focused on renewables and distributed energy systems. Many of the witnesses discussed the imminent danger that climate change presents and the failure of the IOUs' IRPs to address the need for aggressive action. Other witnesses contended that coal and gas perpetuate climate issues because of greenhouse gas emissions, and further, that the utilities should stop investing in hydraulic fracked gas infrastructure, including the Atlantic Coast Pipeline. Several owners of independent small hydroelectric plants testified in opposition to the assumption in Duke's IRPs that no existing PURPA small hydroelectric contracts would be renewed.

DISCUSSION

The Commission finds and concludes that the record in this proceeding includes sufficient detail to allow the Commission to decide all contested issues without the necessity of a further hearing. The Commission commends the utilities and intervenors for the quality of presentation and analyses. The following sections

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summarize issues significant to the Integrated Resource Plans filed by the utilities and reflect the full record in the proceeding.

PEAK AND ENERGY FORECASTS

Public Staff Comments - Peak and Energy Forecasts

The Public Staff reviewed the 15-year peak and energy forecasts (2019–33) of DEP, DEC, and DENC. The compound annual growth rates (CAGRs) for the forecasts are within the range of 0.7% to 1.0% for DEC and DEP and 0.7% to 1.5% for DENC. The Public Staff noted that all of the utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs. They commented that with any forecasting methodology, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future. The Public Staff noted that in its Compliance Filing, DENC revised the peak demand forecasts it filed in its May 1, 2018 IRP, modeling them using the PJM DOM Zone non-coincident peak forecast, which resulted in a significant reduction of peak demand over the forecast horizon.

In assessing the reasonableness of the forecasts, the Public Staff first compared the utilities' most recent weather-normalized peak loads to those forecasted in their 2017 IRP updates. The Public Staff then analyzed the accuracy of the utilities' peak demand and energy sales predictions in their 2012 IRPs by comparing them to their actual peak demands and energy sales. They commented

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that a review of past forecast errors can identify trends in the IOUs' forecasting and assist in assessing the reasonableness of the utilities' current and future forecasts. Finally, in reviewing DEC and DEP's IRPs, the Public Staff reviewed the forecasts of other adjoining utilities in the VACAR region and the SERC Reliability Corporation.

In regard to DEC and DEP, the Public Staff commented that except for a brief time in the 1980's, the dominant seasonal peak has occurred during summer afternoons. The Public Staff noted that the Companies' annual peak sporadically occurred in the winter season, but since 2013, all of DEP's annual peaks have been during January or February, while DEC's annual peaks have occurred during both the winter and the summer seasons. After DEC and DEP experienced their all-time system peaks in February 2015, they conducted a new reserve margin study, the results of which were incorporated in their 2016 and 2018 IRPs. The Public Staff stated that DEC's and DEP's 2018 IRPs forecast DEP to be a winter peaking system and DEC to be a summer peaking system; however, DEC's planning is based on the winter season. The Public Staff further noted that DEP's weather normalized winter peaks have grown at annual rates significantly greater than the growth rates in DEP's peak forecast. For DENC, the Public Staff commented that its 15-year forecast in the Compliance Filing is based on PJM's peak load and energy sales forecast, scaled down for the Dominion load serving entity, which predicts that DENC will become a winter peaking system in 2024.

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Public Staff Comments - DEP's Peak and Energy Forecasts

The Public Staff noted that since the 2016 IRP, DEP has projected that it will be a winter peaking system and winter planning utility. It stated that DEP's forecasted winter peak loads reflect a combined average growth rate (CAGR) of 0.7% over the forecast years of 2019 through 2033, which is significantly lower than the 1.2% CAGR in its 2016 IRP and the 1.2% CAGR in its 2014 IRP. The Public Staff pointed out that as with DEC's 2018 IRP and DEP's prior IRPs, relatively little demand reduction is forecasted as being available from EE and DSM programs during the winter seasons, a 0.2% reduction in the CAGR from EE through 2033 of DEP's system peaks and a reduction of the winter demands from DSM by approximately 4%. The Public Staff noted that DEP expects to have the ability to reduce its summer peak loads by 7% through DSM. According to the Public Staff, over the next 15 years, the average annual growth of DEP's winter peak is projected to be approximately 127 MW and the winter peaks are projected to be approximately 604 MW greater than the forecasted summer peaks.

The Public Staff noted that DEP's energy sales, including reductions associated with its EE programs, are predicted to grow at a CAGR of 0.5%, a significantly lower growth rate than the 0.9% in the 2016 IRP and the 1.0% in the 2014 IRP. Further, the Company's EE programs are predicted to reduce its energy sales by approximately 1% in 2019 to 3% in 2033 according to the Public Staff.

The Public Staff's review of DEP's actual and weather adjusted peak load forecasting accuracy for one year showed that DEP's 2017 IRP forecast underestimated the actual 2018 winter peak load by 17%, and by 11% using a weather-normalized peak. When the Public Staff compared the current forecast to the 2012 IRP forecasts for 2013 – 2018, DEP's forecasts indicate a mean average error (MAE) of 9%. Each of the six forecasts used to calculate the MAE was lower than the actual loads, reflecting forecast errors ranging from -18% in 2018 to -0.3% in 2014. The MAE fell to 6% when the forecasts were compared with weather-adjusted loads.

The Public Staff also reviewed DEP's 2012 energy sales forecast, based on the 2012 IRP forecasts for 2013 - 2018, calculating a 13% MAE, reflecting actual sales being significantly less than expected. The Public Staff noted that DEP predicts that over the next 15 years, its EE programs will reduce its annual energy sales by approximately 0.5% in 2019, increasing to 3% in 2033. In addition, the Public Staff found it noteworthy that DEP's predicted load factor is approximately 51% over the next 15 years, significantly lower than the average 55% load factor predicted in the 2016 IRP and the 56% load factor predicted in the 2014 IRP. According to the Public Staff, a decreasing load factor generally indicates a greater need for peaking plants.

The Public Staff found the economic, weather-related, and demographic assumptions underlying DEP's 2018 peak and energy forecasts to be reasonable, but stated that the excessive forecast errors associated with DEP's winter peak indicate that review and revision of DEP's statistical and econometric forecasting practices may be warranted. However, the Public Staff expressed concerns that

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DEP's actual winter peaks were significantly greater than predicted; such that the 9% MAE equates to an average forecast that is 1,456 MW lower than predicted.

Public Staff Comments - DEC's Peak and Energy Forecasts

The Public Staff commented that DEC's forecasted winter peak loads reflect a significantly lower CAGR of 1.0% as compared to the 1.3% CAGR in its 2016 IRP and 1.4% CAGR in its 2014 IRP. The Public Staff pointed out that relatively little demand reduction is forecasted as being available from EE and DSM programs during the winter seasons: a forecasted 0.1% reduction in the CAGR of DEC's system peaks due to EE programs and a reduction in winter demand from DSM programs of approximately 2%. For summer peak loads, the Public Staff noted that DEC forecasts being able to reduce its summer peak loads by 6% through use of DSM. The Public Staff noted that the predicted average annual growth of DEC's winter peak is 186 MW over the next 15 years, as compared to 232 MW in the 2016 IRP and 286 MW in the 2014 IRP. The Public Staff stated that DEC's energy sales, including the effects of its EE programs, are expected to grow at a CAGR of 0.9%, as compared to a 1.0% growth rate in the 2016 IRP and 1.4% in the 2014 IRP. Further, the Company's EE programs are expected to reduce energy sales by approximately 1% in 2019 and 4% in 2033.

The Public Staff's review of DEC's actual and weather adjusted peak load forecasting accuracy for one year indicated that DEC's 2017 IRP forecast was under-predicted by 4% and that on a weather-normalized basis, the actual peak was 2% greater than predicted. When the accuracy of DEC's forecasts is reviewed

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since 2012, the Public Staff's analysis shows the 2012 IRP yielded a MAE of 5%. It further showed that of the six predicted load forecasts comprising the MAE, two were higher than expected and four were lower than expected, and that the MAE fell to 4% when the forecasts were compared with peaks that were adjusted for abnormal weather.

The Public Staff made a similar review of DEC's 2012 energy sales forecast, which had a 13% MAE. The Public Staff noted that DEC predicts that over the next 15 years, its EE programs will reduce its annual energy sales by approximately 0.8% in 2019, increasing to 4% in 2033. Further it commented that DEC's predicted load factor remains reasonably constant at 58% over the next 15 years, similar to the 59% load factor in the 2016 IRP and the 57% load factor from the 2014 IRP.

The Public Staff concluded that the economic, weather-related, and demographic assumptions underlying DEC's 2018 peak and energy forecasts were reasonable, but that DEC has overestimated its energy sales relative to the 2012, 2014, and 2016 IRPs. The Public Staff noted that DEC had maintained in discussion that its retail energy sales forecast is reasonably accurate when adjusted for abnormal weather. The Public Staff stated that since the Company continues to reduce the predicted growth rates for its projected energy sales and as the peak demand forecast has a direct influence on its capacity expansion plans, the Public Staff places more weight on its review of the Company's peak demands. Noting that the MAE based on actual versus forecasted loads was 5%, but fell to 4% when compared using weather-normalized loads, the Public Staff

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concluded that DEC's peak load and energy sales forecasts were reasonable for planning purposes. The Public Staff recommended that both DEC and DEP continue to review their winter peak equations in order to better quantify the response of customers to low temperatures. The Public Staff suggested that the Companies may wish to evaluate multiple approaches such as a single equation that relies on multiple observations that focus on customer's response to cold weather in January and February, in conjunction with a separate equation that examines responses during July and August. Given the different customer responses to extreme cold and winter temperatures, the use of separate equations for the summer peak and winter peak may allow for improved understanding of how customers respond to extreme temperatures, which is in contrast to Duke's current use of a single equation for all twelve months of the year.

Public Staff Comments - DENC's Peak and Energy Forecasts

Noting that DENC will become a winter peaking system in 2024, the Public Staff pointed out the faster CAGR of 1.5% for DENC's winter peaks as compared to a 0.7% CAGR of its summer peaks. The Public Staff stated that the predicted winter peak CAGR is slightly higher than the 1.3% growth rate from the 2016 IRP, while the CAGR for the summer peak is significantly lower than the 1.5% CAGR from the 2016 IRP. It noted that while the DOM Zone is predicted to become a winter peaking system, PJM is a summer peaking system and thus the Company must procure adequate capacity for the summer peak demand forecast. To do so, the Company's IRP is modeled to procure both supply-side and demand side resources with the annual forecast of summer peak demands. According to the

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Public Staff, on average over the 15-year forecast, the winter peaks are approximately 173 MW greater than the forecasted summer peaks, DENC's EE programs are predicted to provide approximately 1% to 2% reduction of the summer and winter peaks through 2033, and the activation of DSM programs is expected to reduce the peak demands by approximately 1% of MW load. The Public Staff commented that the average annual growth of DENC's winter peak is predicted to be 267 MW and 124 MW for the summer peak over the next 15 years, as compared to the 293 MW annual growth of its summer peaks from the 2016 IRP.

The Public Staff stated that DENC's Compliance Filing projected average annual energy sales growth of 0.7%, a significant decrease from the 1.5% growth rate of the 2016 IRP, and a decrease from the original IRP forecast of 1.4%. It noted DENC's estimate that its EE programs would reduce its energy sales by approximately 2% by 2033, as opposed to the 1% reduction in energy sales due to EE forecasted in its 2016 IRP.

The Public Staff's review of DENC's actual peak load forecasting accuracy for one year showed that DENC's 2017 IRP over-predicted the 2018 summer peak load by 7% and under-predicted the 2018 winter peak load by 15%. The Public Staff reviewed DENC's peak load forecasting accuracy based on the 2012 IRP forecasts for 2013 - 2018. Its review indicated that all of the predicted annual peak demands were greater than the actual peaks, with a MAE of 6%, while its energy

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sales from the 2012 IRP generated an 11% error rate, with four of the previous six annual peaks occurring during the winter season.

The Public Staff stated that based on its review of DENC's forecast accuracy and pattern of predicting loads greater than the actual loads, it supported DENC's use of the relatively lower PJM peak demand forecast as ordered by the VSCC. The Public Staff found DENC's revised peak load and energy sales forecasts to be reasonable for planning purposes, but noted the growing dominance of morning winter peaks, which appears to represent a shift in the use of electricity and warrants further examination of the Company's econometric and statistical forecast models.

Summary of Growth Rates

The following table summarizes the growth rates for the IOUs' system peak and energy sales forecasts in their IRP filings.

2019- 2033 Growth Rates

(After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	0.8%	0.7%	1.0%	127
DEC	1.0%	1.0%	0.9%	186
DENC	0.7%	1.5%	0.7%	124

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Public Staff Areas of Concern and Recommendations - Peak and Energy Forecasts

In its comments on Duke's IRPs, the Public Staff identified several areas of concern, including peak load forecasts and use of smart meter data. In regard to peak load forecasts, the Public Staff expressed concern about DEP's forecast errors of its winter peaks. It noted a continuing pattern of under-forecasting, pointing out that DEP's weather-normalized winter peak of 15,165 MW for 2018 is over 1,000 MW greater than the predicted 2019 winter peak of 14,161 MW. The Public Staff also expressed concern regarding the predicted annual growth rate of DEP's winter peaks of 0.7%, which is a significant departure from the 3.0% CAGR of its actual winter peaks from 2013 through 2018, and 2.1% CAGR of its weather-normalized peaks. It noted the faster growth of DEP's winter peaks over its summer peaks, as opposed to the more balanced growth of DEC's summer and winter peaks.

A key area of concern for the Public Staff with DEP's winter forecasting accuracy was that all of the Company's peaks occurred in the winter season and all of the errors were due to forecasts being below the actual peak demands; as compared to DEC's errors being balanced between forecasts both too high and too low. The Public Staff posited that one reason for the growing dominance of DEP's winter peak may be the lack of heating alternatives to electric heat pumps in DEP's service area, pointing out that heat pumps rely on inefficient heat strips or resistance heating at certain operating conditions. It stated that a second reason

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may be that natural gas is relatively less available in DEP's service area than DEC's territory.

The Public Staff recommended that Duke evaluate alternative equations and modeling tools that would provide a check on forecasts based on monthly data, as it questioned whether the equation is accurately modeling customer's responsiveness to extreme weather, especially in relation to extreme cold temperatures in the DEP service territory. The Public Staff also noted that the data period used for the regression ended on December 31, 2017, excluding the extreme cold that occurred over several days in January 2018. The Public Staff stated that it may be appropriate to expand the data period to include the full winter season to better capture customers' response to extreme weather.

The Public Staff also noted that it had asked Duke how it used smart meter usage data in developing and informing the Companies' load forecasting models and developing improved rate designs, but neither of the utilities reported incorporating usage data obtained from smart meters in its load forecasting models. Additionally, the Public Staff stated that an Integrated Volt-Var Control (IVVC) program could be utilized to provide a variety of grid services to enhance the operability of the grid (e.g., peak reduction), as well as provide a cost savings aspect to ratepayers. The Public Staff indicated that while it had not fully reviewed the cost-benefit analysis and assumptions of an IVVC program installed on the DEC system, it recommended that DEC should continue to revise its estimates and cost benefit analysis for the IVVC program in future IRP filings, and consider

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scenarios that take into account the impact of multiple assumptions, including the installation of IVCC, on the capacity need. The Public Staff recommended that as smart meters are deployed and data from those meters becomes available, the utilities should include in their IRPs a discussion on how they are using that data to inform their load forecasting and improved rate designs.

The Public Staff also recommended that the Companies continue to review their winter peak equations in order to better quantify the response of customers to low temperatures. The Public Staff further recommended that DEC and DEP continue to review their load forecasting methodology to ensure that assumptions and inputs remain current and use appropriate models quantifying customers' response to weather, especially abnormally cold winter weather events.

In regard to DENC, the Public Staff recommended that the Company's 2020 IRP rely on the PJM coincident peak scaled down for the DENC load serving entity forecast for its baseline peak and energy forecasts and encouraged the Company to present its internal peak demand and energy forecasts as a comparison and to allow for a sensitivity analysis with an alternative expansion plan.

SACE, the Sierra Club, and NRDC Comments - Peak and Energy Forecasts

SACE, the Sierra Club, and NRDC retained Wilson Energy Economics to evaluate the peak load forecasts used in the 2018 IRPs. According to comments filed by SACE, the Sierra Club, and NRDC, the load forecast is a major factor determining a utility's need for new resources to meet system energy and demand. Overstating load growth will result in excess capacity on the system, and excess costs borne by ratepayers. Wilson Energy Economics concluded in its report, Review and Evaluation of the Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans (Wilson Report)[5] that the Companies' forecasts are generally consistent with recent load trends and the various economic, demographic, and efficiency-related independent variables that drive the energy forecasts. However, the Wilson Report found the retail peak forecasting methodology to be quite simple, with only brief documentation, and it was unable to evaluate the wholesale forecast models due to lack of information. It also found that while the wholesale projections were generally consistent with anticipated future contract quantities, DEP's forecasts of its wholesale customers' winter peaks were somewhat in excess of aggregate wholesale contract quantities. The Wilson Report stated that despite multiple recent occurrences of unusually cold weather and associated high loads, the Companies' winter peak forecasts were in a reasonable range.

The Wilson Report included a number of recommendations for future IRPs. First, the Companies should research the drivers of the very high loads that have occurred in each service territory under very cold weather and develop a more sophisticated model of how extreme winter weather affects their loads. The Companies should also undertake targeted engagement with customers to prepare a tailored plan to mitigate winter load spikes under future extreme cold events and develop focused demand response and energy efficiency programs to

[5] Comments of SACE, the Sierra Club, and NRDC, Attachment 3 (Docket No. E-100, Sub 157), dated March 7, 2018.

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reduce these peak loads. The Wilson Report recommended that the Companies provide more comprehensive documentation of their peak load forecasting methodology, make use of a broader set of high load data and an enhanced relationship between weather conditions and load, and consider providing sensitivity analysis of the peak forecasts to key drivers and assumptions. Additionally, the Wilson Report recommended that the Companies develop a more effective method for estimating historical weather-normalized peak loads and provide historical aggregate wholesale firm commitments, with weather-normalized historical peaks estimated for the wholesale customer loads separately. Finally, the Wilson Report recommended that the Companies further evaluate wholesale customers' contribution to system peak loads.

Environmental Defense Fund Comments- Peak and Energy Forecasts

EDF points out that using load forecasts that are too high can lead to costly excess capacity. It recommends that the Commission carefully analyze the utilities' load growth assumptions, including a thorough backcast analysis, to determine whether the load growth assumptions are reasonable.

NCSEA Comments – Peak and Energy Forecasts

NCSEA pointed out that while Duke continues to promote its grid improvement plans, the plans are not reflected in the IRPs. NCSEA notes that Duke's grid improvement plans include IVVC, which will allow Duke to manage distribution and allow the utilization of peak shaving and emergency modes of operation.

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Attorney General Office Reply Comments – Peak and Energy Forecasts

The Attorney General's Office (AGO) indicated that it agreed with the Public Staff's initial comments regarding Duke's failure to incorporate IVVC programs in its IRP and supported the recommendation that Duke include the impacts of such programs in its load forecasts in its "future years of capacity planning." The AGO also recommended that Duke evaluate new technologies that may enhance the savings from IVVC and agreed with the Public Staff that Duke should take advantage of the granular data available from smart meters in its load forecasting.

Duke Reply Comments - Peak and Energy Forecasts

Duke notes that the Public Staff generally found DEC and DEP's 2018 IRP load forecasts to be reasonable for planning purposes and compliant with Commission rules and requirements. In response to the Public Staff's recommendation that the Companies continue to review their winter peak equations in order to better quantify the response of customers to low temperatures, Duke stated that the Companies continue to review and improve the load forecast peak model specifications in accordance with the Commission's June 27, 2017 Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans in Docket No. E-100, Sub 147 (Sub 147 Order,) and that it had recently completed an extensive review of the entire peak load forecasting process, including load definition verification, peak weather methodology, and model specification.

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In response to the Public Staff's recommendation that it include in its forecasted load the projected impact of IVVC programs and NCSEA's statement that Duke Energy continues to promote its grid improvement plans, but does not reflect it in its IRPs, Duke noted that the original grid improvement plan proposed by the Companies in DEC's last general rate case in Sub 1146 did not contain an IVVC program for DEC, but that based upon stakeholder feedback, a DEC IVVC program is now planned and will be reflected in future IRPs.

In response to the recommendation of the Public Staff that DEC and DEP continue to review their load forecasting methodology to ensure that assumptions and inputs remain current and to use appropriate models quantifying customers' response to weather, especially abnormally cold winter weather events, Duke pointed out that its review of the peak forecasting methodology in 2018 led to raising the peak forecast significantly. As it receives additional history, the peak forecast process should continuously adapt to changing weather and demand trends, including higher forecasted peaks if extreme winter weather becomes more prevalent as opposed to being an outlier. The Companies cautioned against attempting to model extreme winter peaking conditions, noting that the Companies' 17% reserve margin is in place to cover such events and that making broad assumptions about customers' actions during an extreme peak period could lead to significant over-forecasting of peak demand.

Duke responded to the recommendation that the Companies include in future IRPs and updates a discussion of their use of data from smart meters to inform their load forecasting, cost of service studies, and rate designs, by agreeing that smart meter data has the potential to be very informative from a load forecasting perspective. Duke pointed to the rulemaking on certain data access issues in Docket No. E-100, Sub 161, which may help inform the load forecasting review, as well as the existing Smart Grid Technology Plan dockets, which provide the Commission and parties with extensive information about smart meters and how DEC and DEP are utilizing this technology and data issues. Thus, while the Companies do not believe that additional formal reporting should be required in the IRPs, they are agreeable to updating the Public Staff on their progress in incorporating smart meter data into the load forecasting process.

Duke noted that SACE, the Sierra Club, and NRDC indicated that they generally found DEC and DEP's 2018 IRP load forecasts to be reasonable for planning purposes and compliant with Commission rules and requirements. In regard to these intervenors' recommendation that the Companies research the drivers of the very high loads that have occurred in each service territory under very cold weather, the Companies pointed to the Public Staff's 2018 IRP comments that noted that primary drivers of high peak demand during extreme temperatures are the predominance of electric heat pumps, and the lack of availability of natural gas as a heating source. Duke noted that these factors are more significant in DEP than in DEC territory, making the DEP region more sensitive to extreme winter weather. The Companies agreed to share information on this topic with the Public Staff and other intervenors as it becomes available.

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In response to the recommendation of SACE, the Sierra Club, and NRDC that the Companies develop a more sophisticated model of how extreme winter and summer weather affects their loads, Duke pointed out that the peak forecast should provide a reasonable forecast of system demand, under the assumption of peak normal weather, and that the model accounts for any historical extreme weather and peak conditions within the past seven years for model specification, and the past 30 years for the development of peak weather normal conditions. The Companies disagreed with the suggestion to modify the current peak model to capture extreme conditions, as it would conflict with the Sub 147 Order and would result in a peak forecast that did not properly model probable growth. Duke noted that the recent extreme winters were clearly outliers, and including historical outliers would result in peak forecasts that may drastically over- or under-forecast peaks. The Companies also disagreed with the Wilson Report's contention regarding the lack of sophistication of the peak models, stating that they continuously evaluate the peak model specifications to improve peak forecast accuracy.

In response to the Wilson Report recommendations that the Companies provide more comprehensive documentation of their peak load forecasting methodology, consider using a broader set of high load data (not just monthly peaks) and an enhanced relationship between weather conditions and load, and provide a sensitivity analysis of the peak forecasts to key drivers and assumptions, the Companies stated they were committed to transparency regarding all aspects

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of the load forecast methodology. The Companies contend that incorporating these recommendations would not produce a reasonable peak forecast.

The Wilson Report also recommended that the Companies develop a more effective method for estimating historical weather-normalized peak loads, and Duke agreed that the peak weather normalization process was important in understanding peak history and evaluating peak forecasts, and as were all processes, the Companies' methodology is "imperfect" due to the dynamic nature of load forecasting. The Companies found the Wilson Report's description of the Companies' weather normalization process inaccurate, disputed the contention that the weather-normalization process does not produce a clear historical trend, and pointed out the weakness of the report's assumption that the underlying drivers of the peak weather normalization history were relatively stable.

In response to the Wilson Report's recommendation that the Companies should provide historical aggregate wholesale firm commitments, estimate weather normalized historical peaks for the wholesale customer loads separately, and further evaluate wholesale customers' contribution to system peak loads, the Companies explained their current energy and demand forecast methodology for wholesale load was like that used for the retail energy and peak forecasts, except all forecasts are econometric models and the Companies incorporate the forecasts of the North Carolina Electric Membership Corporation and the North Carolina Eastern Municipal Power Agency as given by those entities.

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DENC Reply Comments - Peak and Energy Forecasts

DENC noted that on June 27, 2019, the VSCC issued its final order on Dominion Energy Virginia's 2018 IRP, and found that the IRP met the requirements of the VSCC's 2018 IRP Order and was reasonable and in the public interest for planning purposes. In response to the Public Staff's recommendations, DENC stated that it is not opposed to showing both the PJM and Company load forecasts for the 2020 IRP. It further committed to studying the effects of the winter peak on its econometric and statistical forecast models either through its own analysis or that of an outside consultant. The Company pointed out that the VSCC had directed the Company to use the PJM load forecast in future full IRP filings.

Commission Conclusions - Peak and Energy Forecasts

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the IOUs peak load and energy sales forecasts are reasonable for planning purposes.

The Commission agrees with the Public Staff that Duke should evaluate alternative equations and modeling tools that would provide a check on forecasts based on monthly data and consider expanding the data period to include the full winter season to better capture customers' response to extreme weather. Further, it is appropriate for the Companies to continue to review their winter peak equations and load forecasting methodology and use appropriate models to ensure that customers' response to extreme weather, especially abnormally cold winter weather events, are appropriately modeled and quantified. The Commission

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also finds that the IOUs should include in their IRPs and updates a discussion of how they use smart meter usage data in developing and informing their load forecasting models and developing improved rate designs. Additionally, to the extent an IOU plans to install new or additional IVVC, its IRP should reflect the impact of installation of IVVC. Finally, the Commission finds it appropriate that DENC's 2020 IRP rely on the PJM coincident peak scaled down for the DENC load serving entity forecast for its baseline peak and energy forecasts and encourages the Company to present its internal peak demand and energy forecasts as a comparison and to allow for a sensitivity analysis with an alternative expansion plan.

RESERVE MARGINS

Public Staff Comments - Reserve Margins

DEP and DEC

The Public Staff explained that based upon the 2016 Resource Adequacy study performed by Astrapé (Resource Adequacy Study), both Companies used a combined 17% reserve margin for planning purposes. The Public Staff noted that the study was warranted due to extreme weather experienced in the Companies' service territories and was first presented during the 2017 IRP update in Docket E-100, Sub 147. The Public Staff pointed out that the use of peak system load for system planning is relevant in the context of the capacity value of solar resources. Both DEP and DEC have target reserves of 17%, with DEP having a 17% minimum reserve over the planning horizon and DEC at 16.8%, and DEP having a maximum reserve over the planning horizon of 33.8% in the summer of 2025 and DEC at 22.4% in the summer of 2023. For the planning period 2019 to 2033, the Public Staff stated that the range of reserve margins reported by the electric utilities continues to be similar to those seen in previous IRPs, i.e., a loss of load expectation (LOLE) of 0.1 days/year of 16.7% for DEC, 17.5% for DEP, and an average of 17.1% for the combined Companies.

The Public Staff noted that in its April 2, 2018, Joint Report with Duke discussing the Resource Adequacy Study, the Public Staff raised several concerns with the Astrapé study, including the use of forced outrage rates, load regression during extreme events, economic load growth error, load multiplier values, and joint utility operations. The Public Staff recommended a 16% reserve margin. On the other hand, Duke argued it was more appropriate to take a holistic view of the study's reasonableness as opposed to focusing on specific individual factors that could potentially result in a lower reserve margin. The Public Staff noted that the Commission's April 16, 2018 Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans, concluded DEC and DEP could continue to use the minimum 17% winter reserve margin for planning purposes, but should present a sensitivity analysis in their resource plan discussion illustrating the impact of a 16% winter reserve margin for planning, including the risk impacts. Duke was also required to address how to model economic load forecast uncertainties in its 2018 IRPs.

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The Public Staff explained that the Companies' 2018 IRPs examined the impact of a 16% reserve margin on the timing of future resource additions as well as on system LOLE. DEC found that a 16% reserve margin would not have any effect on future resource additions, and that LOLE would increase to 0.116 days/year, or one expected firm load shed event every 8.6 years. DEP found that the 16% reserve margin would reduce its short-term market purchases and defer a portion of the combustion turbine (CT) blocks in 2029 and 2032 by two years each. The Public Staff also noted that DEP calculated a LOLE of approximately 0.13 days/year based upon these changes, which is equivalent to one expected load shed event every 7.7 years.

In addition to the effects of a 16% reserve margin, the Public Staff noted that Duke's IRPs addressed load forecast error (LFE) assumptions involving uncertainty and probability distribution. With respect to LFE uncertainty, the Public Staff explained that the Companies presented additional Resource Adequacy Study results with no LFE that indicated that the required reserve margin is only 0.28% less than the Public Staff's recommendation of 16%. The Public Staff further noted the Companies' belief that there is meaningful load growth uncertainty over a two to four-year period, requiring reserves greater than 0.28%

With respect to LFE probability distribution, the Public Staff pointed out that the Companies predict a symmetrical probability distribution, where there is equal likelihood of a significant under or over-forecast. However, the Public Staff's LFE probability distribution used a log-normal distribution so that the probability of a

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lower-than-expected economic growth rate is greater than a higher-than-expected economic growth rate. The Public Staff noted that Duke indicated that it found it inappropriate to use the over-forecast bias recommended by the Public Staff.

The Public Staff stated that it continues to believe that use of a 2-year LFE is appropriate, given that IRPs are required to be filed every two years and that the effects of cold weather outages should be removed. The Public Staff noted that it agreed with Duke that several modeling and market assistance assumptions should be revisited in the next resource adequacy study. As such, the Public Staff continued to recommend a 16% reserve margin, but indicated its willingness to work with the Companies to reach consensus within the constructs of the next resource adequacy study.

DENC

The Public Staff noted that DENC, as a member of PJM, is a summer planning and summer peaking utility, and generally considers summer peak load as the load upon which the reserve margin is based. The Public Staff pointed out that in its original filing, DENC used PJM's reserve margin of 15.9%, adjusted based on the coincident factor between the DOM Zone coincidental and non-coincidental peak load, resulting in a reserve margin target of 11.7%. This reserve margin calculation is the same in both the original IRP and the Compliance Filing, but the Public Staff noted that the load forecast is reduced to comply with the VSCC Order in DENC's Compliance Filing. The Public Staff pointed out that the original

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IRP projected a deficit under Alternative Plan E of 5,275 MW, while the Compliance Filing projects a deficit of 3,028 MW – a 43% reduction in capacity need by 2033.

SACE, the Sierra Club, and NRDC Comments - Reserve Margins

Based on conclusions set out in the report of James F. Wilson entitled, Review and Evaluation of the Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans,[6] SACE, NRDC, and the Sierra Club commented that the reserve margins used in the 2018 IRPs were improperly inflated.

In his report, Mr. Wilson noted that the reserve margins used in the 2018 IRPs were based upon recommendations in the DEC and DEP 2016 reserve margin studies prepared by Astrapé. He opined that the risk of very high loads under extreme cold was substantially overstated in the 2016 resource adequacy studies, primarily due to the faulty approach to extrapolating the increase in load due to very low temperatures. Mr. Wilson noted that winter resource adequacy risk was also overstated due to the demand response and operating reserve assumptions applicable to winter peak conditions. He stated that the winter resource adequacy risk was substantially overstated relative to the risk in summer and other periods of the year, and thus recommended that the winter/summer capacity values of solar resources proposed for use in the 2018 IRPs, as well as the avoided capacity cost weightings proposed for use in the Companies' Schedule

[6] Comments of Southern Alliance for Clean Energy, the Sierra Club, and Natural Resources Defense Council, Attachment 4 (Docket E-100, Sub 157) dated March 7, 2019.

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PP filed in Docket No. E-100, Sub 158, be rejected, and much more balanced seasonal weights be developed. Mr. Wilson also stated that both winter and summer risk were further overstated due to the economic load forecast uncertainty assumptions, greatly overstating the risk of large and unexpected increases in peak load. Thus, he concluded that the recommended increases in DEC and DEP's reserve margins (relative to IRPs before 2016) are unsupported and unnecessary.

NCSEA Comments - Reserve Margins

NCSEA presented a report prepared by Synapse Energy Economics (Synapse Report) that included a Clean Energy scenario for DEC and DEP that used an EnCompass capacity expansion and production cost model. The Clean Energy scenario reflected certain assumptions and costs including a reserve margin set at 15%. NCSEA stated that the lower reserve margin was consistent with North American Electric Reliability Corporation (NERC) standards and reflected the assumption that as older units with higher forced outage rates retire and are replaced with new capacity, system reliability is improved. According to the Synapse Report, with a 15% reserve margin, the EnCompass model projects no loss-of-load hours or hours with unserved energy. According to the report, this proves that the retirement of fossil fuels and build-out of renewables leads to no new system reliability issues.

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Duke Reply Comments - Reserve Margins

Duke noted its compliance with the Commission's April 16, 2018 Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans in Docket No. E-100, Sub 147, accepting the parties' Joint Report and concluding that DEC and DEP may continue to utilize the minimum 17% winter reserve margin for planning purposes in their 2018 IRPs. In addition, Duke noted that the Commission ordered DEC and DEP to further address the economic load forecast uncertainty issue in their 2018 IRPs and to present a sensitivity analysis in their 2018 IRPs that illustrates the impact of a 16% winter reserve margin, including the specific risk impact (LOLE) of using a 16% minimum reserve margin versus a 17% minimum reserve margin.

In regard to the economic load forecast uncertainty assumptions, Duke stated its belief that the Public Staff's load forecast uncertainty assumptions overstate the probability that actual load will be at or below the Companies' forecast levels, and that use of the Public Staff's assumptions reflect a probability of over forecasting load approximately 48% of the time and under forecasting load approximately 17% of the time. Duke contended that the load forecast uncertainty should reflect possible loads that are equally likely to fall either above or below the forecast. Duke pointed out that the Public Staff's recommended 16% reserve margin is only 0.28% greater than the reserve margin needed with perfect forecasting knowledge, indicating a need for more reserves.

In response to Mr. Wilson's contention that including multi-year economic load forecast uncertainty in the resource adequacy studies is not appropriate and suggesting other short lead-time actions, Duke noted that such alternatives are not always sufficiently available or practical to satisfy a resource deficit, particularly large quantities of demand response and EE programs. Duke noted DEP's 600 MW increase in winter peak since the 2017 IRP Update, contributing to an approximate 2,000 MW near-term need for capacity and energy, and the fact that additional steps beyond the market solicitation it conducted may be necessary to maintain the 17% reserve margin. Duke noted that its options are limited and so including only one year of load forecast uncertainty, as suggested by Mr. Wilson, to establish a long-term reliability planning target is inadequate.

In response to Mr. Wilson's criticisms of the methodology used to capture the relationship between winter load and cold temperatures, Duke termed Mr. Wilson's suggestion that it exclude 15 years of the 36-year weather history used in the study because it reflects colder temperatures compared to other historical years as "irresponsible." Duke noted that pursuant to the June 27, 2017 Order accepting the Companies' 2016 IRPs, the Public Staff and the Companies reviewed the cold weather load modeling in the 2016 studies and performed a sensitivity analysis reducing the regression equations significantly for temperatures below the levels seen in recent years that showed only a 0.3% decrease in reserve margin when the sensitivity reduced the cold weather impact by half of that assumed in the base case. Duke stated the sensitivity only impacted seven occurrences in the 36-year weather history. Duke also pointed out that the

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variability in load due to temperature extremes that was modeled in the 2016 resource adequacy studies for DEC and DEP were at or below the peak load variability included in the 2018 PJM Reserve Requirement Study. Based on these factors, the Companies concluded that the modeling of extreme cold included in the 2016 studies was reasonable.

Duke called Mr. Wilson's claim that over 1,000 MW for DEC, and about 750 MW for DEP, of operating reserves were held back in the SERVM model resulting in firm load curtailments "grossly inaccurate." Duke argued that Mr. Wilson's recommendation that the Companies' demand response winter assumptions be "brought up to the summer level" was extremely optimistic and not reasonably achievable in the near term, if at all. Duke noted the more limited achievable potential of winter DSM, and practical difficulties with existing programs.

In response to the 15% reserve margin targeted in NCSEA's Synapse Report, Duke noted that the 15% is based on the NERC 2018 Long Term Reliability Assessment, but that SERC members perform individual reliability assessments, and SERC does not provide reference margin levels for its subregions. Duke also pointed out that the NERC assessment states that NERC applies a 15% margin for predominantly thermal systems if a reference margin is not provided by a given assessment area. Duke argued that the Synapse Report ignores the 17% reserve margin requirement developed through a study focused on issues facing the DEC and DEP systems, and instead used a NERC study that did not consider the level of solar penetration facing the Carolinas, a major driver of the increased reserve

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margin requirement. Duke pointed out that the reserve margin must not only meet expected demand, but also reliably serve customers under extreme and unexpected circumstances.

Duke stated that a holistic review and consideration of resource adequacy study inputs and assumptions is appropriate when judging the reasonableness of the study results, and noted that while some parties may believe that certain study inputs and assumptions may have been overstated, the Companies believe that certain assumptions in the 2016 studies, including outage rate modeling and market assistance assumptions may have understated the required reserve. The Companies noted their plan to work with the Public Staff to refresh inputs and assumptions and complete new resource adequacy studies in support of their 2020 IRPs. The Companies endorsed the prudency of maintaining a minimum 17% winter reserve margin to provide adequate reliability and satisfy the target of less than one firm load shed event every ten years.

DENC Reply Comments - Reserve Margins

DENC stated that it did not oppose the Public Staff's recommendation that DENC should in future IRP filings provide PJM's capacity value for renewable resources as comparison benchmark, and, to the extent the Company's calculated capacity values or methodology differ from PJM's, provide a justification for the difference, and committed to provide that information in its 2019 IRP Update. The Company noted that in its VSCC Final Order, the VSCC directed the Company in future full IRPs to model future solar PV tracking resources using both the actual

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capacity performance of Company-owned solar tracking fleet in Virginia using an average of the most recent three-year period; and a capacity factor of 25%. DENC also agreed to evaluate incorporating a sub-hourly analysis into the 2020 IRP. The Company pointed out that it uses internal information to establish the adjusted reserve margin and coincidence factor and that the use of advanced analytical techniques requires a level of detail not provided in the PJM forecast. Thus, the Company will use available internal data and forecasts to evaluate the feasibility and benefits of advanced analytical techniques in its 2020 IRP.

Commission Conclusions - Reserve Margins

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the reserve margins included in the utilities' IRPs are reasonable at this time for planning purposes. However, the Commission notes the concerns outlined by the Public Staff, as well those discussed in Mr. Wilson's report, and concludes that they should be acknowledged by DEC and DEP and fully addressed in their 2019 IRP updates. Further, DEC and DEP should continue to evaluate the methods and assumptions in their 2016 Resource Adequacy Studies, and continue to work with the Public Staff and other stakeholders when performing future Resource Adequacy Studies. Additionally, DEC and DEP should continue to present a 16% reserve margin sensitivity analysis in future IRPs.

Further, the Commission notes that the Synapse Report's use of a 15% reserve margin in the Clean Energy scenario "reflects an optimized view of the

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Duke Energy service territory with relaxed assumptions around operation and up-to-date renewable costs." Further, the 15% reserve margin is based on national NERC standards, as opposed to resource adequacy studies that take into account the specific characteristics of Duke's systems. As such, the Commission declines to adopt the Synapse Report's recommended 15% reserve margin at this time.

SYSTEM PEAKS AND USE OF DSM RESOURCES

Public Staff Comments - DEP's System Peaks and Use of DSM Resources

The Public Staff noted that DEP's 2018 annual system peak demand of 16,191 MW occurred on January 7, 2018, at the hour ending 7:00 a.m., at a system-wide temperature of 11 degrees Fahrenheit (ºF). DEP activated its DSM resources and reduced its winter peak hourly load by 225 MW. The Public Staff noted that during the Company's nine other highest hourly winter loads, DEP activated its DSM six more times when the average system temperature was between 15ºF and 24ºF.

Based on the Public Staff's comments, DEP's summer system peak of 13,403 MW occurred on June 19, 2018, at the hour ending 5:00 p.m., at a system-wide temperature of 94ºF. DEP activated its DSM resources and reduced its summer peak hourly load by 22 MW. During the Company's nine other highest hourly summer loads, the Public Staff noted that DEP activated its DSM program five more times between 91ºF and 93ºF.

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Public Staff Comments - DEC's System Peaks and Use of DSM Resources

The Public Staff noted that DEC's 2018 annual system peak demand of 19,436 MW, occurred on January 5, 2018, at the hour ending 8:00 a.m., at a system-wide temperature of 12ºF. DEC's summer system peak was 18,008 MW occurred on June 19, 2018, at the hour ending 4:00 p.m., at a system-wide temperature of 94ºF. According to the Public Staff, DEC did not activate any of its DSM resources during either the winter system peak or the summer peak. During the Company's nine other highest hourly winter peak loads, DEC activated its DSM program during five of those hours when the average temperature at the peak was 10ºF and 13ºF degrees. In regard to the nine other highest hourly summer loads, the Public Staff noted that DEC activated its DSM once during its ninth highest hourly load, when the average temperature was 91ºF.

In its recommendations regarding Duke's IRPs, the Public Staff recommended that the Companies maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high, as well as to ensure reliability. The Public Staff also recommended that the Companies' DSM resource forecast represent the reasonably expected load reductions that are available at the time the resource is called upon as capacity. Finally, the Public Staff proposed that DEC and DEP investigate the potential for new time-of-use rate designs that could encourage customers to shift usage from peak to off-peak periods, particularly during winter peaks.

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Public Staff Recommendation - DENC's System Peaks and Use of DSM Resources

The Public Staff noted that DENC's 2018 annual system peak of 17,792 MW occurred on January 7, 2018, at the hour ending 8:00 a.m., at a system-wide temperature of 7ºF. DENC's summer system peak of 16,528 MW occurred on July 2, 2018, at the hour ending 5:00 p.m., at a system-wide temperature of 9°F. The Public Staff indicated that DENC activated DSM during both of these peaks. During its 15 highest peak loads from July 2017 through August 2018, the Public Staff noted that DENC activated its Residential AC Cycling program nine times and its Distributed Generation program 13 times over the 15 highest peak demands.

Public Staff Conclusions - System Peaks and Use of DSM Resources

The Public Staff acknowledges that load conditions, energy prices, generation resource availability, and customer tolerance for the use of DSM are all important considerations in determining which DSM resources should be deployed. Use of DSM resources is largely dependent on the circumstances and cannot be prescribed in any definitive manner. Nevertheless, the Public Staff concluded that the utilities should maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high.

In its review of DENC's DSM activations at the time of its 15 highest hourly peaks, the Public Staff notes an ongoing concern regarding the difference in DSM resources available in the winter and the summer due, in part, to the fact that winter season programs are typically not cost effective. The Public Staff stated that DENC activated its Distributed Generation program during the Company's 2018 winter peak and most of the other near peaks during the winter season; however, the activations only led to 4 - 6 MW of load reduction. As with DEC and DEP, the Public Staff recommends that each IOU investigate and implement any cost-effective DSM that would be available to respond to the growth of the winter peak demands.

DENC Reply Comments – System Peaks and Use of DSM Resources

DENC stated that it would continue to identify and seek approval to implement DSM/EE programs that are cost effective or meet public policy goals. In regard to designing DSM programs to meet winter as well as summer peak demands, the Company noted that its Distributed Generation program is currently available only in Virginia during winter periods to non-residential customers who meet participation requirements based upon size. The Company also pointed out that it had recently received approval for a demand response residential thermostat control program in Virginia and would be filing the program for approval in North Carolina in July, 2019. DENC also indicated that ten new EE programs had been approved by the VSCC in May 2019. These programs would also be filed in North Carolina for approval in July 2019, and would address both summer and winter peaks as well as energy requirements. The Company pointed out that while demand response programs reduce peak periods explicitly, EE programs also provide reductions during winter hours, though the reductions are not dispatchable. Finally, the Company indicated that it was participating in a stakeholder process to help it identify potential opportunities for EE and demand response that will address both summer and winter peak hours.

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Commission Conclusions - System Peaks and Use of DSM Resources

The Commission shares the concern expressed by the Public Staff regarding the difference in DSM resources available in the winter compared to the summer, especially given the increased sensitivity in planning for winter loads and resources. The Commission agrees with the Public Staff that additional emphasis should be placed on defining and implementing cost-effective DSM programs that will be available to respond to winter peak demands. Further, it is appropriate for the utilities to maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high. The utilities should ensure that their DSM resource forecast represent the reasonably expected load reductions that are available at the time the resource is called upon as capacity. Finally, the utilities should investigate the potential for new time-of-use rate designs that could encourage customers to shift usage from peak to off-peak periods, particularly during winter peaks.

ENERGY EFFICIENCY (EE) FORECASTS AND PROGRAMS

Public Staff Comments – DEC and DEP's EE Forecasts and Programs

The Public Staff' stated that its review of DEC and DEP's DSM/EE forecasts and programs indicated that the Companies had complied with the requirements of Commission Rule R8-60 and previous Commission orders regarding the forecasting of DSM and EE program savings, as well as the presentation of data related to those savings. DEC and DEP included information about their DSM/EE portfolios similar to the information reported in their 2017 IRP updates. The Public

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Staff opined that DEC and DEP appropriately addressed the changes in their forecasts of DSM and EE resources and the peak demand and energy savings from those programs. The Public Staff noted that while DEC's forecast did not change by more than 10%, DEP's forecast did vary by more than 10%.

The Public Staff noted several factors that will continue to affect the utilities' ability to develop and implement cost-effective EE programs: changes to federal standards for future lighting measures to take effect January 1, 2020, changes in other appliance standards, and efforts to modify building and energy codes. The Public Staff also pointed to recent decreases in the utilities' avoided costs that have decreased the value of avoided energy and capacity benefits from an EE program, making it more difficult to design, implement, and maintain cost-effective programs. Further, the large contribution of EE savings to portfolios from lighting measures are unlikely to continue beyond one to two more years. Additionally, technologies such as space heating/cooling and building envelop measures will continue to face similar headwinds.

The Public Staff stated its belief that an increased nationwide emphasis on EE is producing EE savings outside of utility-sponsored programs; these EE savings are being incorporated into the IRP load forecasts. Factors influencing load forecasts include the "roll-off" of utility EE savings, savings from more stringent appliance and lighting standards, more efficient heating and cooling equipment, greater emphasis on incorporating efficiency standards into building and energy codes, self-installation of EE measures by large commercial and

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industrial customers, and consumer adoption of EE. While measuring the EE embedded in the load forecasts is challenging, the Public Staff states its belief that EE has contributed to the lower sales growth rates identified in the utilities' IRPs, which is likely to continue into the near future.

The Public Staff pointed out that DEC does not offer any residential DSM program that can be used during winter peaking events, while DEP's EnergyWise program offers a limited DSM program for controlling water heaters and strip heat on heat pumps in its western service area. The Public Staff also noted that DEC had received Commission approval to cancel a pre-Senate Bill 3 water heater load control program in its most recent general rate case because the costs of continuing the program exceeded the benefits.

The Public Staff stated that it has worked with utilities to find new cost-effective programs to reduce residential demands during winter peaking events, but no program design has proven to be cost-effective. The Public Staff indicated that it would continue to encourage utilities to look for new residential DSM opportunities, including the potential for new rate designs that incorporate a more dynamic pricing structure. According to the Public Staff, new time-of-use schedules have the greatest potential to help residential customers curtail loads during winter peaking events. Further, as smart meter technologies are deployed and more customer data become available, customers should have the opportunity to better understand their usage patterns and how those patterns impact system peaks, offering residential customers opportunities to curtail load.

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The Public Staff indicated that DEC's and DEP's portfolios of EE programs are not materially different from those in their 2016 IRPs and 2017 IRP updates, and that they continue to align their new and existing DSM and EE programs. The Public Staff also noted that as observed in the last few DSM/EE rider proceedings, both utilities' portfolios continue to shift the source of EE savings away from lighting measures toward behavioral programs such as the My Home Energy Report. The Public Staff pointed out that DEC's projections of portfolio energy savings decline by approximately 9% and DEP's by 20% from the energy savings identified in their 2017 IRP updates. Both DEC and DEP continue to treat DSM as a capacity resource and EE as a reduction to their load forecast.

The Public Staff explained that both utilities produce EE-related savings through their respective portfolios of EE programs over the measure lives of each program. At the end of the measure's life, the utilities assume that as customers replace EE measures with other as or more efficient measures, those savings will continue in the form of reductions to the load forecast, which is designated as historical savings ("roll-off" savings). New measures are separately identified and incorporated into the load forecast tables as new savings. The Public Staff noted that the assumption that EE measures will be replaced with other or new measures differs from the assumptions Duke uses regarding non-utility generator (NUG) contract renewals as discussed *infra*. The Public Staff indicated that the use of these different assumptions may affect the timing and type of resources in the IRP.

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As discussed in regard to peak forecasts, the Public Staff recommended that DEC and DEP put a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands. Additionally, the Public Staff recommended that DEC and DEP continue to identify any changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold for which a discussion is required.

Public Staff Comments - DENC's EE Forecasts and Programs

The Public Staff commented that DENC's portfolio of EE programs has undergone significant changes since the 2017 IRP update and that changes to the portfolio are greatly influenced by the DSM/EE activities of Dominion Energy Virginia and the decisions of the VSCC. The Public Staff indicated that DENC's 2018 IRP reduced the energy savings by 30% over the planning horizon from the savings identified in the 2017 IRP update, primarily due to the cancellation of several programs in Virginia that had been offered on a system-wide basis. The Public Staff noted that DENC requested approval for a North Carolina-only program from the Commission for any program that was cost-effective on a North Carolina-only basis.

The Public Staff also noted that DENC completed a market potential study in late 2017 that identified 3,042 GWhs of achievable savings over a ten-year period, but the measures identified in the market potential study have not been incorporated into DENC's 2018 IRP. The study found that the greatest economic

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potential for residential and non-residential sectors was in lighting and space heating and cooling measures. However, the Public Staff noted that there were no recommendations for specific measures that would contribute toward the achievable potential for either customer class, and the achievable potential excluded the impact of customers eligible to opt-out of utility-sponsored EE portfolios.

The Public Staff explained that while the market potential study would likely have limited influence on DENC's EE portfolio, Virginia Senate Bill 966, the "Grid Transformation and Security Act of 2018", or GTSA,[7] would more likely drive the Company's future EE deployment. Under the GTSA, the Company is required to spend $870 million over the next ten years on EE, including existing and new EE programs. The Public Staff noted that the Company had filed 11 DSM/EE programs for approval before the VSCC, which the Commission notes were approved by the VSCC in April.[8] The proposed portfolio of 11 new programs has a spending projection of approximately $262 million over the next five years, and the Company has indicated that this will count toward the $870 million targeted by the GTSA. The Public Staff stated that DENC's 2018 IRP does not include impacts

[7] 2018 Virginia Acts of Assembly, Ch. 296 (effective July 1, 2018).

[8] *Petition of Virginia Electric and Power Company for approval to implement demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia*, Order Approving Programs and Rate Adjustment Clauses, Case No. PUR-2018-00168 (May 2, 2019).

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from these proposed programs. DENC filed eight of the programs for approval before this Commission on July 13, 2019.[9]

As it recommended for DEC and DEP, the Public Staff recommended that DENC put a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands, and that it continue to identify any changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold for which a discussion is required. The Public Staff also recommended that the IOUs continue to pursue all cost effective EE and DSM. Finally, the Public Staff proposed that DENC should continue to evaluate the potential to cost-effectively implement an EE program on a North Carolina-only basis, should the program be denied approval by the VSCC to implement the program on a system-wide basis.

SACE, the Sierra Club, and NRDC Comments - EE Forecasts and Programs

SACE, the Sierra Club, and NRDC commented that the Duke IRPs underutilize cost-effective energy efficiency. They state that DSM/EE should be evaluated on a level playing field with supply-side resources by allowing the planning models to "select" DSM or EE as a resource, or by modeling varying levels of efficiency without screening out a subset of efficiency potential based on flawed assumptions. SACE, the Sierra Club, and NRDC argued that in developing the 2018 IRPs, Duke limited the amounts of EE available as a resource using an

[9] Docket No. E-22, Subs 567-574.

overly restrictive screening process, biasing the planning model in favor of supply-side options. They also pointed out that Duke's planning process does not allow EE to be easily compared with supply-side resources in a capacity expansion model. As a result, SACE, the Sierra Club, and NRDC state that these flaws lead to underutilization of cost-effective EE and thus a "preferred" portfolio with a cost higher than necessary.

In regard to the EE forecasts, SACE, the Sierra Club, and NRDC noted that while Duke projects significant, though declining, savings on peak from its DSM/EE portfolio in the near term, Duke expects those savings to rapidly drop off in the out years of the planning horizon. Specifically, DEC assumes no new DSM capacity will be added after 2024, and projects decreasing reductions to peak from EE investments after 2027. Likewise, DEP projects no growth in its Energy Wise for Business, Large Curtailable Load, or CIG Demand Response DSM programs after 2024; and little growth in savings from EnergyWise for Home after 2022. The limited growth in summer peak load impacts from DEP's DSM programs comes from its Distribution System Demand Response program, while DEC anticipates no additional growth in load impacts from its DSM programs after 2023. SACE, the Sierra Club, and NRDC point out that the Duke IRPs show EE and DSM resources remaining static or shrinking year after year.

Attorney General Initial Comments - EE Forecasts and Programs

The AGO noted that DEC and DEP modify their load forecasts to incorporate the effects of both "naturally occurring" and EE measures implemented

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in response to government mandates. It noted that for the planning years 2018-2027, Duke includes levels of EE based, in whole or in part, on its five year program plan. The AGO stated that there may be additional cost-effective EE resources that could be implemented and that it was unclear to what extent Duke considered these additional resources. Like SACE, the Sierra Club, and the NRDC, the AGO recommended that the Companies evaluate EE resources on a level playing field with other resources and allow its models to select all cost-effective EE resources during years 2019-2027.

Attorney General Reply Comments - EE Forecasts and Programs

In reply comments, the AGO contended that Duke should implement a more robust consideration of DSM/EE measures, which should be modeled as supply-side resource alternatives so that a least-cost resource portfolio is selected. According to the AGO, Duke's IRPs fail to give sufficient attention to the potential of using modern EE measures or encouraging energy management to reduce peak demand. The AGO engaged an outside expert, Strategen Consulting, LLC (Strategen) to review Duke's IRPs and the initial comments of intervenors. A memorandum prepared by Strategen was attached to the AGO's reply comments (Strategen Memo). The AGO agreed with the Public Staff that in light of increasing winter peaks, DSM/EE programs geared to winter are particularly needed. Strategen discussed advanced DSM programs that have been cost-effective in other jurisdictions, such as "Bring Your Own Device" ("BYOD") programs where customers to supply a device such as a smart thermostat that could shave winter

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peaks. Strategen pointed to one BYOD program specifically designed to lower winter peak demand by accessing customer battery storage systems on cold winter nights and providing customers with incentives based on the amount of energy transferred to the grid.

The AGO recommended that Duke be required to revise its models so that DSM/EE programs are evaluated alongside supply-side resources, not overlook innovative advances, and develop new DSM/EE programs focused to provide resources during winter peaking.

Duke Reply Comments - EE Forecasts and Programs

Duke disagreed with the criticisms of SACE, the Sierra Club, and NRDC regarding the Companies' projections of DSM/EE peak savings in the later years of the IRP noting that the DSM projections were based on the Companies' past experience with customer acceptance of these programs and the expectation that the amount of DSM capacity savings will reach a steady level after the first few years of the IRP forecast. Duke stated that the forecasts reflect a continued effort to add new customers, while recognizing that customer response to these programs has been limited. In regard to the impact of EE programs on peak demand, Duke noted that incremental annual EE savings projection levels are similar throughout the entire forecast period as later period EE projections are offset by older EE programs that have reached the end of their useful life. Duke explained how it is appropriate to remove the savings from these older programs from the cumulative amounts of EE would result in "double-counting" the impact of the EE programs, and thus the Companies' approach to DSM/EE in the 2018 IRPs is appropriate.

DENC Reply Comments - EE Forecasts and Programs

In response to the Public Staff's comments, DENC stated that it would continue to identify and seek approval to implement DSM and EE programs that are cost effective or meet public policy goals. The Company noted that it had recently received approval for a demand response residential thermostat control program and ten EE programs in Virginia[10] and would be filing these 11 programs for approval in North Carolina in July.

Commission Conclusions - EE Forecasts and Programs

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the IOUs' approach to utilizing economic and achievable EE potential, linked to avoided cost calculations, is appropriate to ensure the cost-effectiveness of EE programs. The Commission agrees with the Public Staff's comments that the utilities complied with the requirements of Commission Rule R8-60 and previous Commission orders regarding the forecasting of DSM and EE program savings, as well as the presentation of data related to those savings. However, the Commission does not

[10] *Petition of Virginia Electric and Power Company For approval to implement demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia, Order Approving Programs and Rate Adjustment Clauses*, Case No. PUR-2018-00168 (May 2, 2019) ("VSCC DSM Order").

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agree with the position of SACE, NRDC, and the Sierra Club that the Duke IRPs underutilize cost-effective energy efficiency.

The Commission appreciates the Public Staff's assessment that several factors continue to affect the IOUs' ability to develop and implement cost-effective EE programs. As noted in its comments, changes in avoided costs, including those pending before the Commission in Docket No. E-100, Sub 158, could make it more difficult to attain cost-effective programs in general. Still, the Commission finds the logical approach of the utilities, linked to avoided costs, valid for planning.

The Commission acknowledges the challenges described in the Public Staff's comments, including the "headwinds" associated with technology improvements, rising standards, and decreasing avoided costs. The IOUs should continue to explain changes of 10% or more in the savings projections from the previous IRP or IRP update. The Commission also finds it reasonable for the IOUs to continue to address major known changes in EE-related technologies, regulatory standards, and other drivers that would impact future projections of EE savings.

The Commission will review and approve, as appropriate, DENC's new portfolio of DSM/EE programs. Finally, the Commission encourages DENC to continue to evaluate additional North Carolina-only programs, if necessary.

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NATURAL GAS ISSUES

For purposes of calculating longer-term avoided energy rates, DEC and DEP propose to use forward natural gas prices through 2028; transition to Duke's fundamental forecast through 2033, which show little growth over the ten year period; and then use an assumption that natural gas prices will grow at 2.5% through 2040. This approach is similar to the approach proposed by DEC and DEP in recent years,[11] and has been the subject of extensive testimony and discussion before the Commission, most recently in the comments filed by parties in the 2018 avoided cost proceeding in Docket No. E-100, Sub 158.

DENC utilized natural gas prices derived from the forward market for natural gas for the first 18 months, and then it gradually (over the next 18 months) blends the monthly prices from the forward market with the monthly prices from the long-term price projection from ICF International, Inc. (ICF).

Public Staff Comments - Natural Gas Issues

The Public Staff commented that it appreciates the difficulty in forecasting long-term prices of natural gas as well as other fuel prices, and found reasonable DENC's reliance on forecasts from ICF. However, the Public Staff expressed

[11] This issue was also addressed in Phase Two of the Sub 140 proceeding, but the focus during that time was primarily consistency between the methodologies used for avoided cost and IRP purposes. In its December 17, 2015, *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 140 (Phase Two Order)*, the Commission directed DEC and DEP to recalculate their avoided energy rates using natural gas and coal price forecasts that were developed in a manner consistent with those utilized in their 2014 IRPs, which at the time relied on market data for the first five years before switching to their fundamental forecast.

concerns with the natural gas price forecasts utilized by DEP and DEC in their 2018 IRPs. As discussed in its Initial Statement filed in Docket No. E-100, Sub 158, which were incorporated by reference, the Public Staff believes that the proposed use of forward natural gas prices for ten years by DEP and DEC leads to natural gas prices that are overly conservative and inappropriate for planning purposes. On page 22 of the Initial Statement, the Public Staff noted that Duke Energy Florida, Duke Energy Kentucky, and Duke Energy Indiana each rely wholly on market prices for the first five years and blend market and fundamental prices for the next five years, before switching to the fundamental forecast for the remainder of the planning period in their IRPs. As in previous IRPs and avoided cost proceedings,[12] the Public Staff indicated its preference for DENC's approach with its use of three years of forward price data before transitioning to its long-term fundamental natural gas price forecast.

The Public Staff noted in its comments that the use of an excessively conservative natural gas price forecast is unlikely to alter DEP and DEC's generation expansion plans, however, the use of a low gas price forecast will depress the avoided energy costs that are paid to qualifying facilities, and also reduce the avoided energy costs that are used to evaluate the cost-effectiveness of DSM and EE programs. Duke's conservative natural gas price forecast is graphically displayed on page 27 of the Public Staff's Initial Statement relative to DENC's natural gas price forecast. Therefore, the Public Staff recommended that

[12] Docket No. E-100, Sub 147, and Docket No. E-100, Sub 148.

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DEP and DEC, in future expansion models, reflect the use of no more than five years of forward natural gas prices before transitioning to their fundamental forecast.

AGO Initial Comments – Natural Gas Issues

The AGO expressed concern that Duke's reliance on natural gas raises a risk that ratepayers will face unanticipated, unmodeled costs from natural gas price volatility.

NC WARN Comments - Natural Gas Issues

NC WARN noted in its initial comments public utility commissions such as in Arizona and Virginia that have rejected proposed IRPs and required utilities to consider opportunities for renewable energy before considering new natural gas infrastructure. NC WARN recommended that the Commission direct Duke to consider battery storage options as opposed to new natural gas infrastructure. NC WARN filed an updated version of its North Carolina Clean Path 2025 Plan, which provides for replacement of 50% of all coal and gas used for electricity with clean energy by 2025, and 100% by 2030. NC WARN's plan indicates that solar combined with battery storage is now more reliable and cost-effective than new natural gas power plants. The Plan indicates that gas turbine manufacturing is declining due to this shift to renewables with storage. The Plan states that Duke's contention that it must build gas turbines to back up solar is "unsubstantiated."

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In its reply comments, NC WARN encouraged the Commission to carefully review Duke's plan to meet demand mostly from resources using fracked gas. It contended that the demand for fracked gas would likely decline as renewable energy technologies grew and battery costs fell. NC WARN also recommended that the Commission reject Duke's proposal to add over 9,000 MW of natural gas infrastructure and direct Duke to seek renewable generation instead. NC WARN contends that Duke's proposal to build natural gas plants and pipelines is not the least-cost option and exposes customers to significant risk.

Duke Reply Comments - Projected Prices for Natural Gas

Duke indicated that it disagreed with Public Staff's recommendation to revise the natural gas fuel price forecast to use no more than five years of forward market data before transitioning to the fundamental forecast. It agreed with the Public Staff that this issue has been the subject of extensive testimony and discussion before the Commission, most recently in the initial comments filed by parties in the 2018 avoided cost proceeding in Docket No. E-100, Sub 158. In response to the Public Staff's proposal that Duke use five years of market data before switching to the fundamental forecast, Duke stated that it had complied with the Commission's directive to maintain consistency between the fuel forecasts presented in IRPs and those used in avoided cost filings, and appropriately proposed changes in the way it utilizes forward prices and long-term forecasts in its IRP, and used the same approach in its biennial avoided cost filings.

Duke indicates that its customers face a $4.5 billion long-term financial obligation and a risk of a $2 billion overpayment risk due to the unprecedented number of Qualifying Facilities whose output the Companies must purchase, along with the use of stale and inaccurate fundamental forecasts to calculate avoided cost rates. Duke states that the continued, regular purchase of ten years of forward market natural gas contracts shows that the market is liquid. Duke notes that in making these purchases, the Companies obtain multiple price quotes that have similar prices, showing that there are multiple sellers in the current market, as well as a lack of price volatility in the 10-year forward natural gas market. Duke also notes that there is another market participant in North Carolina similarly purchasing significant quantities of ten-year forward natural gas. Thus, Duke argues that use of 10-year forwards in IRPs is appropriate for evaluating future generation needs and for comparing long-term purchase power obligations from QFs required under PURPA.

In response to the contention of the AGO, Duke states that it already considers the impacts and future costs from natural gas price volatility in the filed IRPs. To assess natural gas price volatility, the Companies consider a range of future fuel price scenarios, including high and low natural gas prices, in the development of their IRPs.

Duke noted in its Reply Comments that NC WARN had again proposed an energy plan that is unrealistic and would endanger the reliability and affordability of the electric power system. Duke attempted to conduct discovery on contentions

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contained in NC WARN's comments and its North Carolina Clean Path 2025 Plan by requesting analytical and factual support. In response, NC WARN referenced reports filed with its 2017 and 2018 IRP Comments, as well as the original and updated N.C. Clean Path 2025 reports, which Duke contended showed a lack of analysis and circular reasoning. As such, Duke argued that the Commission should not rely on NC WARN's conclusions, which if implemented, would endanger the reliability and affordability of energy in the State.

Commission Conclusions - Natural Gas Issues

The Commission recognizes the impact of key supply-side variables; such as projected fuel prices on the IRP forecasts. While the Commission acknowledges Duke's concern with the over-payment risk associated with stale avoided costs; this risk of changing costs and assumptions extends to the building of assets with lives of over thirty and forty years. These risks make it evident that utility planning requires sound forecasts and proper forecasting practices.

In this proceeding, the Commission again recognizes the important relationship that exists between the biennial avoided cost proceeding and the IRP, as well as the importance of maintaining internal consistency between these proceedings. Given the growing use of natural gas-fired generation, the importance of having a sound and reasonable natural gas price forecast has also grown. In this proceeding, the Public Staff argued that Duke's reliance on ten years of forward market price data tends to lead to gas price forecasts lower than is appropriate. This practice may lead to an excessive reliance on natural gas-fired

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generation relative other forms of generation; such as solar and battery storage. The Public Staff instead proposed the use of a limited number of forward prices of three to five years, combined with a fundamental forecast, arguing that after year five the current market is not so robust as to supplant the predictions of market analysts. The Commission notes that as shown by the Public Staff, Duke's other operating utilities do not use ten years of forward prices and this practice is highly uncommon in the electric utility industry. The Commission further finds that this reliance on thinly traded future prices over extended periods brings additional risks that should not be borne by ratepayers.

The Commission finds that DEC's and DEP's use of long-term forwards is inappropriate for use in their future IRPs. As such, DEC and DEP should file 2019 IRP updates and subsequent IRPs and updates that incorporate recalculation of their avoided energy rates using natural gas price forecasts that more appropriately reflect the use of forward market prices for no more than five years before transitioning to their fundamental forecasts for the remainder of the planning period.

The Commission accepts that the fuel forecasting methodology utilized by DENC is also appropriate for Integrated Resource Planning in this docket.

RELICENSING OF EXISTING NUCLEAR PLANTS

Public Staff Comments - Relicensing of Existing Nuclear Plants

The Public Staff commented that one of the significant issues faced by the utilities is the pending expiration of operating licenses for nuclear energy resources

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in the next 20 to 30 years. According to the Public Staff, current schedules call for retirement of approximately 5,900 MW in the 2030 to 2034 period and the loss of an additional approximately 8,400 MW in the 2036 to 2046 period. The following table summarizes the current license expiration dates for the utilities' nuclear facilities.

Name	Utility	Summer Capacity (MW)	License Expiration Date
Robinson Unit 2	DEP	741	July 2030
Surry Unit 1	DENC	838	May 2032
Surry Unit 2	DENC	838	January 2033
Oconee Unit 1	DEC	847	February 2033
Oconee Unit 2	DEC	848	October 2033
Oconee Unit 3	DEC	859	July 2034
Brunswick Unit 2	DEP	932	December 2034
Brunswick Unit 1	DEP	938	September 2036
North Anna Unit 1	DENC	948	April 2038
North Anna Unit 2	DENC	944	August 2040
McGuire Unit 1	DEC	1158	June 2041
McGuire Unit 2	DEC	1158	March 2043
Catawba Unit 1	DEC	1140	December 2043
Catawba Unit 2	DEC	1150	December 2043
Harris Unit 1	DEP	928	October 2046

The Public Staff noted that the Nuclear Regulatory Commission (NRC) has issued initial regulatory guidance documents that may ultimately provide an option to operators of commercial nuclear power facilities for extension past the current 60-year licenses (subsequent license renewals or SLRs). Any additional license

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extension will be evaluated by the utility based on the specific risks and costs associated with each unit. The Public Staff indicated that there are three SLR applications under review by the NRC, including Dominion Energy's Surry Units 1 and 2. Further, Dominion Energy has filed a letter of intent with the NRC to apply for SLRs for its North Anna Units 1 and 2.

The Public Staff noted that while there is uncertainty whether further license extensions may be granted, DEC and DEP have stated that they each view "all of its existing nuclear fleet as excellent candidates for SLRs, based on current conditions and expected operating expenditures, regardless of future carbon constraints."[13] DEC indicates that work continues on development of the Oconee Nuclear Station SLR.

The Public Staff recommends that the Commission continue to direct the utilities in future IRPs to include a discussion and evaluation of potential SLRs for all of their existing nuclear units, including an evaluation of the risks and required costs for upgrades, and to reflect any such relicensing plans in future IRPs.

DENC Reply Comments - Relicensing of Existing Nuclear Plants

DENC commented that with respect to existing generating facilities, the Public Staff recommended that the Commission direct the IOUs in future IRPs to include a discussion and evaluation of potential SLRs for all of their existing nuclear units, including an evaluation of the risks and required costs for upgrades,

[13] DEC IRP at 48; DEP IRP at 49.

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and to reflect any such relicensing plans in future IRPs. DENC committed to include such discussion in its future IRPs.

Commission Conclusions - Relicensing of Existing Nuclear Plants

The Commission agrees with the Public Staff's recommendation that the utilities should continue to include a discussion and evaluation of potential SLRs for all of their existing nuclear units, including an evaluation of the risks and required costs for upgrades, and to reflect any such relicensing plans in future IRPs. The Commission finds that the discussion and analyses included in the current docket by the IOUs complied with this directive.

CAPACITY VALUE OF SOLAR

Public Staff Comments – Capacity Value of Solar

The Public Staff commented that the assumption of both DEP and DEC regarding the contribution of solar energy to peak capacity has a significant impact on future capacity requirements. According to the Public Staff, even a small adjustment in the percent of nameplate capacity available at peak demand has the potential to delay or even eliminate the need for additional capacity. As such, the Public Staff recommended that the issue of aggregate solar generation coincidence at peak for both winter and summer be evaluated further, given the growing importance of solar generation in North Carolina.

The Public Staff noted that in prior IRPs, DEC and DEP calculated the capacity value for solar facilities by averaging actual solar output at the typical peak

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load hour, using several years of historical load data. The Public Staff indicated that this methodology provided a reasonable estimate for how much intermittent, non-dispatchable capacity would be available during the system peak. For their 2018 IRPs, Duke retained Astrapé Consulting (Astrapé) to perform a reliability-based analysis using techniques similar to those used in resource adequacy planning. The Capacity Value of Solar study (CVS Study) modeled each Company's system at varying levels of solar capacity to identify the timing of projected firm load shed events for each level of solar penetration, and the contribution of solar during those hours. This analysis establishes the capacity value of solar resources, as well as the seasonal allocation of LOLE.

The CVS Study results are presented in the form of a seasonal capacity value for each level of solar penetration in DEC and DEP, with different values for fixed and tracking solar photovoltaic (PV) because tracking results in a higher capacity value. Using these findings, Duke then discounts the amount of installed solar capacity, both utility and third party-owned, by this capacity value in each utilities' Load, Capacity, and Reserves Tables (LCR Tables),[14] thereby reducing the amount of available capacity and increasing the need for traditional thermal resources to meet peak system load. Using the values from the CVS Study, as opposed to its previously used coincident peak method, the need for traditional resources in 2033 increases by 138 MW in DEC and 168 MW in DEP.

[14] DEC IRP, Tables 12-E and 12-F; DEP IRP, Tables 13-E and 13-F.

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The Public Staff expressed concern regarding the difference between how Duke plans to meet its peak system load and how it values the capacity contribution of solar resources. In past IRPs, the Companies discounted the available solar capacity to match the estimated solar output during the hour of peak system load, and thus planned future resource additions to meet the peak system load, and also considered the availability of solar resources during that same peak system load.

The Public Staff contended that use of the CVS Study results effectively bifurcates the treatment of solar resources and the treatment of traditional utility-owned thermal resources. By discounting the solar contribution based on its output during projected firm load shed events (High Risk Hours), yet planning future resource additions to meet the output needed during the hour of peak system load (Peak Load Hours), the actual contribution of solar resources during the Peak Load Hours is ignored. The Public Staff also pointed to the disparate treatment of solar resources versus dispatchable thermal resources, which receive a capacity value of 100%, despite their not having guaranteed availability at the time of all High Risk Hours due to planned and forced outages.

The Public Staff proposed that DEC and DEP either plan future capacity resource additions based upon the estimated load during High Risk Hours or discount the capacity value of solar resources by their output during the Peak Load Hours, rather than their output during High Risk Hours. The Public Staff proposed a coincident peak methodology that relies upon utility data and statistical analysis to determine the capacity value, and can be applied to any intermittent resource with a history of hourly generation data. According to the Public Staff, this methodology addresses the perceived disconnect between Peak Load Hours and High Risk Hour, and considers both the operational history of intermittent resources in each utility's service territory and forecasted system operational models that employ numerous assumptions related to load forecasting, solar output, and generation performance characteristics. The Public Staff stated that while it did not have access to the models used by Duke in determining the future resource need, it estimates that using the capacity values produced using its methodology would delay the need for future resource additions.

The Public Staff also noted that the CVS Study considers such factors as load uncertainty and unit outages when it calculates LOLE and capacity value, and that these factors may lower solar capacity value and increase the required minimum reserve margin. The Public Staff contends that these factors should cause either an increased reserve margin or a decreased solar capacity value, but not both. Thus, the Public Staff is concerned that the need for future resource additions may be overstated.

The Public Staff recommended that DEC and DEP utilize the coincident peak methodology for establishing the capacity value of solar, rather than the Astrapé Solar Capacity Value Study. For planning purposes in this IRP, the Public Staff recommended that DEC and DEP use a Capacity Value for solar of 3% in winter and 55% in summer. Finally, the Public Staff recommended that the

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Commission require DEC and DEP to file a report discussing the impact of this change, and if the first year of capacity need changes, in the 2018 avoided cost proceeding.

In regard to DENC, the Public Staff recommended that DENC continue to discuss mitigation strategies to address high levels of solar penetration and system operations, including revising and improving its estimates of both fixed and variable integration costs. Further, to the extent that the Company identifies required mitigation strategies to address the aggregate effect of distributed solar PV, such as the addition of a supplemental CT to address generation volatility or ramp rates, the Public Staff stated that those applicable costs should be assigned to the overall installed cost of solar.

The Public Staff pointed out that PJM publishes a methodology for calculating capacity values for non-dispatchable resources and recommends using a three-year average of historical wind and solar facility output during the summer peak hours to determine the applicable capacity value for use in reserve margin planning. For facilities less than three years old, PJM publishes "class average capacity factors" for use in the determination of capacity values. The Public Staff indicated that DENC's proposed capacity values for solar are significantly lower than the PJM class average, and recommended that DENC continue to evaluate renewable resources' contribution to coincident peak and update its models to reflect the additional research. The Public Staff also recommended that in future IRPs and updates, the Commission require DENC to provide PJM's capacity value

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for renewable resources as comparison benchmark, and to the extent that DENC's calculated capacity values or methodology differ from PJM's, provide a justification for the difference.

The Public Staff also noted that it had recommended in the avoided cost docket that DENC's proposed re-dispatch cost be reduced based on the Public Staff's proposed modifications. The Public Staff agreed that a re-dispatch or solar integration charge are important concepts as increasing levels of intermittent and non-dependable generation are added into the electrical grid. The Public Staff recommended that to the extent possible, the modeling programs used by the utilities within the IRP process for selection of future projects evaluate and use appropriate price signals to reasonably demonstrate the costs to ratepayers as new generation units are selected.

SACE, the Sierra Club, and NRDC Comments - Capacity Value of Solar

SACE, the Sierra Club, and NRDC contended that Duke undervalues the capacity that solar provides to the DEC and DEP systems, which diminishes the planned deployment of solar resources over the planning horizon. These parties described Duke's data and its method for calculating solar capacity values as being severely flawed, resulting in a dramatic undervaluing of solar's capacity benefit to Duke's systems. SACE, the Sierra Club, and NRDC engaged James F. Wilson, who prepared a *Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing,* included as Attachment

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4 to their filing. These parties stated that Duke's projections also fail to account for likely improvements in solar technology and use technical values at the low end of the range based on projects put in service in recent years.

SACE, the Sierra Club, and NRDC recommended that Duke reevaluate its projections for addition of new solar resources. They noted that DEP's IRP projects that it will add 1,441 MW of solar to its system over the next 15 years, with approximately 1,000 MW of this growth occurring in the next five years, coincident with its solar procurement obligations under House Bill 589. Thereafter, solar on the DEP system would increase by only another 11.6 percent over the following 10 years (from 2023 to 2033). Likewise, DEC plans to more than double the installed solar on its system in the first five years (2019-2023), with solar additions growing at a much slower rate thereafter.

According to SACE, the Sierra Club, and NRDC, these projections reflect neither the recent trends in accelerated solar installations in the Carolinas, nor the continuing steep cost declines for solar. Additionally, these parties contend it is unreasonable for Duke to plan for such small investments in what is proving to be the least-cost generating resource. Therefore, these parties recommend that Duke reevaluate its projections for future solar installations using more realistic assessments of current and likely future cost declines and improved panel efficiencies.

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Attorney General Initial Comments – Capacity Value of Solar

The AGO stated Duke's assessment or solar resources may undervalue the peak load contribution from solar technologies. The AGO noted that the capacity values for solar identified in Duke's Astrapé study are much lower than the results found in a similar study performed by the National Renewable Energy Lab in California, where solar resources have a higher penetration rate.[15]

Attorney General Reply Comments – Capacity Value of Solar

The AGO indicated that it shared concerns similar to those expressed in the Initial Comments of the Public Staff and SACE, Sierra Club and NRDC regarding Duke's representation of the capacity value of solar. The AGO stated that the calculation of solar capacity value warrants further scrutiny to ensure that solar is not being undervalued as a capacity resource in the IRP, so that Duke's IRP does not include more traditional thermal capacity resources than necessary.

On behalf of the AGO, Strategen reviewed Duke's analysis and indicated that there are aspects of Duke's capacity value calculation that could potentially be biased against solar resources. First, Duke's analysis shows declining capacity value as solar penetration increases in subsequent MW tranche additions, and it is unclear whether each subsequent solar tranche also included changes to the underlying load and non-solar resources on Duke's system. Strategen noted that

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[15] J. Jorgenson, P. Denholm, and M. Mehos, National Renewable Energy Laboratory, Estimating the Value of Utility-Scale Solar Technologies in California Under a 40% Renewable Portfolio Standard, (May 2014), www.nrel.gov/docs/fy14osti/61685.pdf.

load growth may occur predominantly in the summer, thus shifting the share of LOLE towards summer months, or the mix of non-solar generators may change towards those with fewer outages. Both of these could affect the calculated solar capacity value.

Strategen also pointed out that Duke's analysis assumes that there are significantly less demand response resources available in winter versus summer, which increases LOLE during winter hours and could decrease solar capacity value. Strategen also noted that Duke's analysis assumes a 25% share of single-axis tracking systems versus 75% fixed tilt. While Strategen found this consistent with historical deployment in the State, it pointed out that other jurisdictions have shown a greater trend towards tracking systems. Additionally, Duke's assumptions regarding the availability of resources from neighboring balancing areas do not reflect the fact that several of the balancing areas neighboring Duke not only have significant excess capacity exceeding their reserve margins, but they are also summer peaking systems.[16] Strategen concluded that modeling these substantial winter resources available from neighboring systems at too low a level could have the effect of increasing LOLE at these times and reducing solar capacity value.

Strategen also noted the Public Staff's contention that Duke's analysis treats solar resources differently than dispatchable thermal, despite the fact that even dispatchable thermal resources are not guaranteed to be available 100% of

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[16] Strategen Memo at 11, citing https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

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the time in High Risk Hours due to planned and forced outages. Strategen agreed that this reflects inconsistent treatment between resource types and recommended that either capacity value of non-solar resources should be de-rated according to their outage rates, or a different methodology be adopted. Strategen also agreed with the Public Staff's observation that Duke's approach of adjusting the combustion turbine value to determine capacity value varies from a traditional study, where load is adjusted to achieve an LOLE of 0.1 events per year. Strategen pointed out that since DEP is modeled as two load centers (east and west), Duke's approach could also lead to a lower solar capacity value than the traditional method, depending on where the combustion turbine is located in the model and what transmission constraints are assumed.

Strategen stated that while conceptually, a framework, such as that used by Duke, can be a sound approach to determining the capacity value of solar for resource planning, more information is needed regarding certain underlying assumptions in Duke's analysis. Therefore, it recommended that for the purposes of the 2018 IRP, the Commission rely on the capacity value of solar recommended by the Public Staff.

Duke Reply Comments - Capacity Value of Solar

In regard to the Public Staff's contention that there is a disconnect between how Duke plans to meet its peak system load and how it values the capacity contribution of solar resources, Duke indicated that it was trying to understand why the Public Staff's proposed capacity values remain static despite the fact that

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possibly over 10,000 MW of solar capacity could be installed in the Carolinas over the next 15 years. Duke noted that Astrapé's CVS study showed each additional tranche of solar capacity provides diminishing marginal capacity value to the system. Duke indicated that it was not clear whether the Public Staff had performed any research into the shift in LOLE, as done by Astrapé, that would support the Public Staff's proposed fixed winter/summer capacity values that do not adapt to the level of solar installed on the DEC and DEP systems. Duke indicated that it would like to continue the ongoing dialogue with the Public Staff on this and other proposed calculations. Duke also pointed to testimony of Brian Horii of the South Carolina Office of Regulatory Staff testimony filed in PSCSC Docket No. 2019-2-E, where he indicated that resources such as wind and solar generation must be evaluated using probabilistic methods that evaluate all hours of a given period, not just a single peak hour. Mr. Horii disputed the appropriateness of using a coincident peak hour approach to valuing the capacity contribution of solar generation on the basis that it fails to recognize the capacity value provided not just by output at the time of the peak hour but also by the output during other peak hours for which there is a non-zero risk of the utility being unable to meet all customer demand.

Duke also disagreed with the AGO's assessment that the Companies may be undervaluing the peak load contribution of solar technologies. The AGO cited a study performed by the National Renewable Energy Lab in California, to support its argument that solar resources may have more capacity value than that attributed by the Companies. Duke responded that while North Carolina is second

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in the country in installed solar behind only California, California has significantly higher solar irradiance than North Carolina, and California's electricity demand profile is significantly different than North Carolina's electricity demand profile simply based on the range of temperatures seen in California versus North Carolina, as well as different sources of heating and cooling. Duke pointed out that consumers in North Carolina and South Carolina have much greater electrical heating and cooling. According to Duke, these differences make a comparison with California meaningless.

DENC Reply Comments - Capacity Value of Solar

In response to the Public Staff's comments, DENC indicated that it is committed to continuing and improving its efforts to analyze solar integration costs, the results of which will be provided in the 2020 IRP. DENC also stated that it intends to further refine its integration costs analysis in future IRPs and updates based on the methodology used in the 2017 and 2018 IRPs. As part of that analysis, the Company committed to consider the costs associated with any identified strategies to mitigate the aggregate effect of distributed solar PV on the Company's system. As previously discussed, DENC also agrees to include in future filings the PJM class average capacity value for solar as a comparison to its proposed capacity value, and provide justification for any difference.[17]

[17] DENC Reply Comments at 9.

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Commission Conclusions - Capacity Value of Solar

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission concludes that the utilities' modeling of solar energy and capacity as presented in the 2018 IRPs are generally reasonable and appropriate for planning purposes in this docket, except as discussed below.

While the Commission recognizes that probabilistic modeling of the capacity value of intermittent resources is increasingly common in reserve margin planning, it is not clear at this time that DEC and DEP accurately modeled the contribution of solar capacity in its IRP. The Commission is persuaded by intervening parties and the Public Staff that a number of assumptions made by Duke may have resulted in a capacity value of solar that is too low, placing unreasonable emphasis on traditional thermal generation at the expense of solar. The Commission finds merit in the Public Staff's recommendation that the issue of aggregate solar generation coincidence at peak for both winter and summer be evaluated further, given the growing importance of solar generation in North Carolina. The Commission finds persuasive the argument that assessing solar resources in a probabilistic manner while assessing thermal resources during peak load effectively bifurcates the planning criteria used to assess future capacity needs. This recommendation is in line with the methodology used by both DENC and Duke and approved by this Commission in prior IRPs, and brings into alignment Duke's treatment of solar resources and utility-owned thermal resources. While the Commission recognizes that there is value in probabilistic

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modeling of solar resources, it also determines that solar's contribution to peak load is an important measure of its value to the ability of the utility to meet its reserve margin. The Commission also adopts the Public Staff's recommendation that DEC and DEP use a Capacity Value for solar of 3% in winter and 55% in summer, and that DEC and DEP should file a report discussing the impact of this change, and if the first year of capacity need changes, reflect the change in the 2018 avoided cost proceeding. The Commission expects that future IRPs will include efforts by Duke to refine its probabilistic modeling approach to more accurately value solar energy's ability to contribute towards Duke's reserve margin, and should reflect ongoing collaboration on this matter between the Public Staff, Duke, and other intervenors.

The Commission also agrees with the Public Staff's recommendation In regard to DENC, that DENC continue to discuss mitigation strategies to address high levels of solar penetration and system operations, including revising and improving its estimates of both fixed and variable integration costs, and assigning the costs to the overall installed cost of solar. The Commission also agrees that in future IRPs, DENC should clarify its definition of a NUG facility, use that definition consistently through the IRP; re-evaluate which generating facilities sell energy directly to DENC and identify them separately from facilities that do not, separately identify facilities that sell energy/capacity directly to DENC from facilities that sell directly into PJM, and be consist in references to nameplate rating or equivalent firm capacity rating. Additionally, DENC should continue to evaluate renewable resources' contribution to coincident peak and update its models to reflect the

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additional research. Further, in future IRPs and updates, DENC should provide PJM's capacity value for renewable resources as a comparison benchmark, and to the extent that DENC's calculated capacity values or methodology differ from PJM's, provide a justification for the difference.

BATTERY STORAGE

In Docket No. E-100, Sub 147, the Commission noted that the evaluations of battery storage technology in the 2016 IRP has "not been fully developed to a level sufficient to provide guidance as to the role this technology should play going forward."[18] As such, it required utilities to "provide in future IRPs or IRP updates a more complete and thorough assessment of battery storage technologies including the 'full value' as discussed in the NCSEA comments. If the standard technical and economic analyses of generation resources somehow preclude the complete and thorough assessment of battery storage technologies, then a separate discussion of this point should be included in the IRPs."[19]

Duke Integrated Resource Plans - Battery Storage

According to the Duke IRPs, DEC and DEP are assessing the integration of battery storage technology into their portfolio of assets. Duke notes that battery storage costs are expected to continue to decline, which may make it a viable

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[18] Docket No. E-100, Sub 147, June 27, 2017 *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans* (2016 IRP Order) at 60.

[19] *Id.* at 60.

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option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value.

Duke notes that energy storage can also provide value to the transmission and distribution (T&D) system by deferring or eliminating traditional upgrades and can be used to improve reliability and power quality to locations on the Company's distribution system. This approach results in stacked benefits which couples value streams from the Transmission, Distribution, and Generation systems. This evaluation process falls outside of the Company's traditional IRP process which focuses primarily on meeting future generation needs reliably and at the lowest possible cost. This new approach to evaluating technologies that have generation, transmission and distribution value is being addressed through the Integrated System and Operations Planning (ISOP) process as discussed later in this Order.

Duke states that it will begin investing in multiple grid-connected storage systems dispersed throughout its North and South Carolina service territories that will be located on property owned by the Company or leased from its customers. These deployments will allow for a more complete evaluation of potential benefits to the distribution, transmission and generation system while also providing actual operations and maintenance cost impacts of batteries deployed at a significant scale. Additionally, the Company continues to participate in an energy storage study to assess the economic potential for customers, as mandated by HB 589. Results of the study are expected in December 2018.

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Duke included battery storage in its screening analysis for the 2018 IRP: a 5 MW / 5 MWh Li-ion Battery, a 20 MW / 80 MWh Li-ion Battery, and 2 MW Solar PV plus 2 MW / 8 MWh Li-ion Battery. In their IRPs, DEC and DEP have included 150 MW and 140 MW of lithium-based battery storage "placeholders" in their Portfolio 1, respectively. This is reflected in their short-term action plans, in which DEC begins with 4 MW deployed in 2020, growing to 60 MW by 2023, and DEP begins with 12 MW deployed in 2019, reaching 64 MW by 2023. Both utilities plan to begin investing in grid-connected storage systems dispersed throughout their service territories, with specific investments identified in DEP's discussion of the Western Carolinas Modernization Project (WCMP).[20]

Both DEC and DEP refer to the planned lithium-based battery storage devices as "placeholders" largely due to the way in which energy storage was modeled in the IRP. First, Duke performs a technical screening of various energy storage technologies. While Duke identifies many types of energy storage, only lithium-ion batteries are actually modeled in System Optimizer and Prosym; the remaining choices are screened out from quantitative analysis for various reasons, including technological feasibility and commercial availability.[21] Traditional generation technologies are made available to the System Optimizer for economic selection, based upon techno-economic characteristics, to meet load and reserve

[20] DEP IRP at 51.

[21] DEC and DEP screen out the following energy storage technologies from future capacity deployments: pumped storage, compressed air storage, liquid air storage, flow batteries, and high temperature batteries.

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margin requirements over the planning horizon. However, energy storage provides a range of benefits, such as transmission investment deferral and ancillary services,[22] which are difficult, if not nearly impossible, to quantify over the long-term period of the capacity expansion model.

To address the difficulty in modeling energy storage, DEC and DEP specified the battery storage capacity to be included exogenously, effectively "forcing" storage into the capacity expansion plan. The cost impact of energy storage was evaluated in the production cost model Prosym, where battery resources were assumed to have the primary responsibility of providing generation, energy, and ancillary benefits, except in cases where the primary purpose was transmission or distribution benefits.[23] Pumped storage, such as the Bad Creek facility, is analyzed using a two-pass approach: First, Prosym runs without energy storage; then, energy storage inflows and outflows are scheduled to levelized marginal costs subject to physical and technical constraints; finally, Prosym is run a second time with the additional scheduled load or generation from pumped storage. This analysis captures the benefits of bulk energy time shifting, but does not quantify additional energy storage benefits as defined in the recently published *Energy Storage Options for North Carolina* study (Storage Study).[24]

[22] *See* the Storage Applications and Services section of the NC State Energy Storage Team's *Energy Storage Options for North Carolina*, at 10-13, https://energy.ncsu.edu/storage/.

[23] DEC and DEP's response to PS DR 4-4.

[24] The full study is available for download at https://energy.ncsu.edu/storage/.

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DEC and DEP discuss the limitations of the IRP in relation to energy storage in a discussion of the insights gained from an analysis of Portfolio 7, which is based on Portfolio 6, except the next planned CT resource is replaced with battery storage. In DEP, this change actually resulted in a lower PVRR than Portfolio 6 (in no sensitivity scenario was Portfolio 7 more cost effective than Portfolio 1 or 2). These projections depend upon the energy storage device being grid-tied and controlled by the utility in real-time. DEC and DEP both conclude that the difficulty in understanding the value of energy storage makes it "important for the Company to operate utility storage on its system to properly evaluate the abilities and value of battery storage."[25]

DENC Integrated Resource Plan - Battery Storage

DENC stated in its IRP that batteries serve a variety of purposes that make them attractive options to meet energy needs in both distributed and utility-scale applications, including providing energy for a power station blackstart, peak load shaving, frequency regulation services, or peak load shifting to off-peak periods. DENC noted that batteries have gained considerable attention due to their ability to integrate intermittent generation sources, such as wind and solar, onto the grid. DENC pointed out that the primary challenge facing battery systems is the cost, and that other factors such as recharge times, variance in temperature, energy efficiency, and capacity degradation are also important considerations for utility-scale battery systems. DENC did not consider batteries for further analysis in the

[25] DEP IRP at 107; DEC IRP at 105.

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Company's busbar curve. However, under the GTSA, DENC is required to propose a plan to deploy 30 MW of battery storage under a new pilot program. In its revisions to its IRP, the Company modeled 30 MW battery storage pilots as a proxy generation resource.

Public Staff Comments - Battery Storage

DEC and DEP

The Public Staff recognized that modeling the various uses of energy storage presents challenges such as capturing and quantifying the various value streams. High capital costs of energy storage (even under assumptions of a 50% decline in capital costs by 2028), coupled with the aforementioned challenges, make it nearly impossible for DEC and DEP's existing modeling software to economically select energy storage in its System Optimizer. The Public Staff noted that DEC and DEP have identified the need for improved modeling capabilities in the Integrated System Operations Planning (ISOP) sections of their IRPs, which envision future IRPs that are capable of recognizing the benefits energy storage can provide on a sub-hourly and "stacked" basis.[26] In addition, the increasing cost of integrating solar energy identified in the Astrapé Ancillary Service Study[27]

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[26] Value stacking refers to the ability of energy storage devices to provide benefits over a range of service categories, i.e., one energy storage facility providing frequency regulation, improved reliability, and transmission asset deferral. *See* Storage Study, p. 137, for a discussion of "value stacking".

[27] Referenced in DEC and DEP's Initial Statement, filed November 1, 2018, Docket No. E-100, Sub 158.

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indicates the need for a more flexible system, which energy storage is well suited to provide. With improved modeling, energy storage could also be assessed for cost-effectiveness in different renewable energy penetration scenarios.[28] The Public Staff encouraged DEC and DEP to continue to enhance their modeling capabilities as described in the ISOP sections of their IRPs, with the eventual goal of accurately quantifying energy storage benefits and costs so that there would be no need to force storage into the IRP modeling.

DENC

The Public Staff noted that DENC discussed battery storage in extremely broad terms, while recognizing that energy storage could provide grid stability as more renewables are integrated into the grid and reduce the intermittency of wind and solar generation. As DENC states did not consider battery storage for further analysis in the Company's busbar curve, the Public Staff concluded that DENC failed to thoroughly assess battery storage technologies or include a separate discussion justifying their absence from the IRP.

The Public Staff stated its belief that DENC did not comply with the Commission's 2016 IRP Order to provide a more complete and thorough analysis of battery storage technologies, as opposed to DEC and DEP's 2018 IRPs where battery storage was included as a technology which their models could select and

[28] Public Service of New Mexico's 2017-2036 IRP retained Astrapé Consulting to quantify the effect of energy storage on reliability and system flexibility at various levels of solar PV penetration, using similar methodologies to Duke's Ancillary Service Study.

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placeholders were input to the model and production cost runs reflected the effect of bulk energy shifting. The Public Staff noted that the Energy Information Administration (EIA) estimates that there were approximately 700 MW of installed battery storage projects at the end of 2017, with 40% of that capacity in PJM.[29] The Public Staff recommended that DENC be required to submit a supplemental filing to its 2018 IRP with a more detailed analysis showing why battery storage technologies were excluded from the Company's busbar curves, including a quantitative analysis of energy storage costs. The Public Staff also noted that DENC should address how its solar integration cost estimates are affected by battery storage, including a discussion of whether the legislatively mandated 5,000 MW of solar could be more cost-effectively integrated if coupled with energy storage technologies in future IRPs and IRP updates.

AGO Initial Comments - Battery Storage

The AGO noted the recent and upcoming additions of solar resources to Duke's generation portfolio, and the even broader opportunity presented by solar resource development with the addition of storage technologies. By pairing these solar additions with energy storage, the capacity value of solar would be preserved, eliminating the need for other capacity resources. The AGO also noted that pairing storage with solar can potentially yield cost advantages by reducing inverter and interconnection costs and allowing the storage component to benefit

[29] EIA, *U.S. Battery Storage Market Trends*, May 2018. Accessed at https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

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from federal investment tax credits. The AGO also pointed to the downward trends in the cost of storage technologies. The AGO contends that Duke notes these trends, but does not thoroughly evaluate them in a systematic way.

The AGO indicated that Duke has used battery storage for use primarily as a tool to support grid stability through frequency regulation, solar smoothing, and energy shifting related to renewable resources, rather than in combination with solar resources as a way to expand contribution to peak hours of demand. The AGO noted that only one solar-plus-storage technology configuration was included in the initial screen of the model used to evaluate resource options, as opposed to nine natural gas-burning technologies, two coal technologies, two nuclear technologies, and two stand-alone storage technologies. The AGO recommended that Duke's IRPs analyze and model costs for a broader range of solar plus storage technologies, including solar plus storage resources utilized in other states.

NC WARN Initial Comments - Battery Storage

NC WARN provided a number of examples of the decline in costs of battery storage and breakthroughs in battery technology. It also highlighted plans of utilities and governmental entities that include substantial amounts of solar coupled with battery storage. NC WARN recommended that Duke redirect its reliance upon gas turbine generation to reliance upon battery storage, especially solar combined with battery storage.

SACE, the Sierra Club, NRDC Comments - Battery Storage

SACE, the Sierra Club, and NRDC noted that Duke had recognized the declining cost of battery storage and included battery storage in its resource plans, but contended that there should be greater additions of grid-connected battery storage. Additional battery storage would support additional solar and other clean energy resources, as well as provide balancing of grid supply and demand, peak shaving, and other benefits. These parties noted the steady fall of the costs of solar-plus-storage technologies, and contended that contracted and demonstrated prices for battery storage are already least-cost compared with traditional fossil fuels in some applications and are expected to continue to fall. Thus, SACE, the Sierra Club, and NRDC recommended that Duke incorporate higher levels of battery storage into its long-term plans.

AGO Reply Comments – Battery Storage

The AGO recommended that given the current broad array of storage technologies with different sizes, configurations, and operating characteristics, modeling should include an array of the alternatives consistent with industry best practice. The AGO indicated that Duke's assessment of battery storage in its 2018 IRPs is insufficient. The AGO points out that storage can address peak demand, can be added in small increments that fit growth, enhances the resilience of the grid during catastrophic events, and may respond faster and more accurately than traditional generators in the face of a disturbance.

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The AGO points out the IRP model provided by NCSEA with its initial comments that incorporates more flexible pairings of solar plus storage resources, which greatly impact results. According to Strategen, NCSEA's model appropriately selects sizes and ratios of solar plus storage that fit a system need and uses publicly available cost estimates, as opposed to Duke's forcing into the model of one option for solar plus storage and using non-public cost information. The AGO concludes that Duke's solar-plus-storage modeling is not flexible enough to provide an effective evaluation and an alternative modeling approach should be required.

NC WARN Reply Comments – Battery Storage

NC WARN agreed with initial comments of the AGO, NCSEA, and SACE, the Sierra Club, and NRDC regarding the need for Duke to incorporate greater amounts of solar plus battery storage into its IRPs based on its cost and reliability.

Duke Reply Comments - Battery Storage

Duke noted that for the first time, it included battery storage as a resource in the 2018 IRPs; in total, nearly 300 MW (nameplate) of lithium-ion battery storage as capacity resource placeholders were assumed to provide 80% of their nameplate capacity towards meeting the Companies' winter peak capacity needs. The Companies also noted their agreement as indicated in their filed IRPs that battery storage costs are expected to continue to decline, making batteries an option for grid support services, including frequency regulation, solar smoothing

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during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value. Duke disputes the AGO's contention that it did not thoroughly evaluate the downward trend of storage technology costs, noting that its IRPs assume that battery storage costs drop by nearly 40% by year 2025 in the IRP Base Case. Duke also indicated that the Companies' IRPs include an aggressive capital cost sensitivity that would further the decline in battery storage costs to 60% by 2025. Additionally, the Companies include a sensitivity of replacing a future undesignated CT with a grid-tied battery storage option in both the DEC and DEP IRPs. Duke also argued that pairing storage with solar to allow "the storage component to benefit from federal investment tax credits as suggested by the AGO may not always be in the best interests of ratepayers." Duke also pointed out that because North Carolina's peak conditions occur in both summer afternoon and winter morning and afternoon, and can be at least several hours in duration, there may be limitations to the capacity value of batteries, particularly batteries charged solely from solar resources. Duke noted the Commission's recent approval of a Certificate of Public Convenience and Necessity for DEP's Hot Springs Microgrid Project, a combination 3 MW (DC) solar and 4 MW lithium-based battery energy storage system. Duke indicated that it is committed to further studying the capacity value of incremental battery storage (both grid-tied storage and solar plus storage systems) in the Carolinas at increasing penetration levels. Duke stated that a study of the capacity value of storage is needed, and that the Companies expect to include the results of a capacity value of storage study as early as the Companies' 2020 biennial IRP filings.

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DENC Reply Comments - Battery Storage

In its reply comments, DENC responded to the Public Staff's recommendation that the Company provide a more detailed analysis of why battery storage technologies were excluded from the Company's busbar curves, including a quantitative analysis of energy storage costs, and address how its solar integration cost estimates are affected by battery storage, including a discussion of whether the legislatively mandated 5,000 MW of solar could be more cost-effectively integrated if coupled with energy storage technologies.

DENC noted that many types of technologies can store energy, with hydroelectric pumped storage, a form of mechanical energy storage, accounting for the greatest share of large-scale energy storage power capacity in the United States. It pointed out that large-scale energy storage capacity additions since 2003 have been almost exclusively electrochemical (or battery) storage, though as of May 2019, there has been limited operating experience in utility scale applications of batteries with 901 MW for the entire United States (298 MW in PJM).

DENC stated that it is in the early stages of battery research and has relied on publically available industry guidance regarding battery storage projects to help evaluate the technology's merits as compared to traditional generation sources. It offered that battery storage can peak shift at a stand-alone storage facility or co-located at a solar farm, as well as improve overall energy production at a solar facility by capturing energy would have been clipped by the inverters. Because, battery storage is still in its early stages of development, DENC's estimates for a

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battery storage facility in the 2018 Plan were more reflective of a pilot program versus a larger utility scale facility. Further, prices for battery storage facilities to provide backup for periods of lower production from solar facilities, were not competitive with CTs in the 2018 IRP short-term action plan slated for deployment in 2022 and 2023. The Company indicated it screened out battery storage resources as part of its future resource analysis because of limited utility scale operating experience, PJM's ongoing revision of its tariffs for energy storage resources due to FERC Order 841, and high costs.

DENC stated that pursuant to the VSCC Order, a 30 MW battery storage pilot program was available as an option in the "final" PLEXOS IRP modeling. The pilot was not chosen by the model as a least-cost option in Plan A, validating the Company's decision in the 2018 Plan to screen out battery storage resources because of their then (i.e., 2018) high cost relative to their benefits as a generating resource. However, the battery storage pilot was forced, into all other Plans (Alternative Plans B through F) as required by the VSCC Order. The Company agreed to include battery storage and other energy storage options such as pumped storage facilities in the busbar analysis and provide the results of that revised analysis in its 2019 IRP Update.

DENC disagreed with the Public Staff's recommendation that it specifically address how its solar integration cost estimates are affected by battery storage. The Company indicated that it will not have sufficient information to analyze batteries' effect on solar integration for the 2020 IRP. However, the Company will

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continue to assess battery storage technologies in future IRPs and IRP updates as required by prior Commission orders, and will report and incorporate the results of any relevant experience with battery storage. Additionally, the Company agreed to model battery storage using the most updated cost estimates available in its future full IRP filings.

Commission Conclusions - Battery Storage

The Commission recognizes the role that battery storage is beginning to play in regards to intermittent distributed generation such as solar and wind. However, the Commission also recognizes the current challenges due to cost-effectiveness, reliability, and useful lives of battery technologies. The Commission is of the opinion that while DEC and DEP have improved their modeling of energy storage since their 2016 IRP, their 2018 IRPs still fall short of capturing the "full value" of energy storage as discussed in the 2016 Order.[30] DEC and DEP should continue to enhance their modeling capabilities with the eventual goal of accurately quantifying energy storage benefits and costs so that there would be no need to force storage "placeholders" into the IRP modeling. Specifically, DEC and DEP shall include additional combinations of solar plus storage in its next IRP, and should put additional emphasis on quantifying benefits other than bulk energy shifting in their IRP Updates, as discussed *supra*. The information required by this

[30] The "full value" of energy storage referred to in the 2016 IRP Order referred to: integration of renewables, peak load shaving, emergency response and resilience, grid stability, and energy cost reduction. Other benefits of energy storage, recognized by DEP in Docket No. E-2, Sub 1185, include frequency regulation.

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Order for future IRP filings shall also reflect the findings from the Technical Conference ordered by the Commission regarding its planned ISOP effort.[31] Further, the utilities should provide pertinent information derived from their active or planned projects that utilize battery technologies.

The Commission recognizes that the utilities in North Carolina may not have sufficient experience to quantify the full value of energy storage. However, as stated in the 2016 IRP Order, if the standard technical and economic analyses of generation resources somehow preclude the complete and thorough assessment of battery storage technologies or they are excluded from the busbar curves, then a full explanation and analysis should be included in the IRPs, including a quantitative analysis of energy storage costs. The Commission concludes that DENC did not appropriately address the requirements of the 2016 IRP Order in its 2018 IRP, and shall include in its 2019 IRP Update a full explanation and analysis, including a quantitative analysis of energy storage costs, which was lacking in its 2018 IRP. Additionally, the Commission agrees with the Public Staff and requires that DENC address how its solar integration cost estimates are affected by battery storage, including a discussion of whether the legislatively mandated 5,000 MW of solar could be more cost-effectively integrated if coupled with energy storage technologies in future IRPs and IRP updates.

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[31] See *Order Scheduling Technical Conference and Requiring Responses to Commission Questions,* July 23, 2019.

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INTEGRATED SYSTEMS OPERATIONS PLANNING (ISOP)

In its IRP, Duke recognizes that the electric utility industry is rapidly changing and that there are "a multitude of new possibilities of assets to serve customers." [32] Recognizing that this adds complexity to the IRP process, Duke states that beginning this year they will begin to expand their planning tools to more fully value some aspects of newer technologies. This includes identifying the locational value of distributed generation sources, more tightly linking distribution plans to bulk power plans, and recognizing the sub-hourly operational impacts of some supply resources. While limited changes are made in this IRP,[33] future IRPs will create a "broader process by which all energy resources are evaluated fully and fairly valued on functional capability." The goal of this ISOP process is to reasonably mimic future operational realities to serve its customers with newer technologies. Duke commits to address the challenges inherent in capturing the capabilities of newer technologies in future IRPs, and looks forward to public feedback.

The ISOP process is particularly important as it relates to battery storage, and Duke explicitly recognizes that realizing the "stacked benefits" of battery storage is a unique evaluation process which falls outside of the traditional IRP

[32] DEC IRP at 31; DEP IRP at 31.

[33] Duke appears to imply that the changes in this IRP include the quantification of the costs of integrating intermittent solar resources, as discussed in Docket No. E-100, Sub 158.

process.[34] Duke states that existing and planned battery storage deployments will allow for a more complete evaluation of the potential benefits to the system, and will work with Generation, Transmission and Distribution departments in the evaluation process.

Public Staff Comments – ISOP

The Public Staff recognizes the complexity of fully valuing battery storage, and encourages the development of improved modeling capabilities envisioned by ISOP.[35] The Public Staff also recommended that in future IRPs, the Companies continue to evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data, and to the extent these advanced analytics are available at reasonable cost, utilize these resources to provide better information and understanding on optimizing reserve margin needs, as well as overall system operations.

EDF Comments – ISOP

EDF commends Duke for using this innovative planning approach, which it maintains can save customers money through deferring or avoiding costly investments. However, EDF recognizes that there are not many details in Duke's

[34] *Id.* at 33.

[35] Initial Comments of the Public Staff at 76.

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IRP, and encourages the Commission to open a rulemaking or separate docket to explore the most effective and systematic way to implement ISOP.[36]

NCSEA Comments – ISOP

In its initial comments, NCSEA is encouraged by the statements made regarding Duke's ISOP process, and compares it to Integrated Distribution Planning (IDP), stating that the proposed ISOP description is similar but for its exclusion of a hosting capacity map.[37] NCSEA criticizes Duke for not including more detail or a timeline associated with ISOP, and calls upon the Commission to create a rulemaking proceeding to implement ISOP in order to establish a set of rules by which the ISOP process is governed. NCSEA believes such a rulemaking procedure would guarantee that the process has sufficient oversight and transparency so as to allow ratepayers real opportunities to see if the investment decisions are in their best interests.

DEC and DEP Reply Comments – ISOP

In its reply comments, Duke contends that it does not oppose a rulemaking, but recommends that the Commission permit a pre-rulemaking stakeholder process to facilitate common understanding of ISOP and IDP. This would allow

[36] Initial Comments of EDF at 5.

[37] Initial Comments of NCSEA at 19.

consensus to be reached on as many areas as possible to make the formal rulemaking process more collaborative and efficient.

Commission Conclusions – ISOP

The Commission believes that efforts by the utilities to improve their IRP process are commendable, and as previously mentioned in this order, sees a more detailed modeling effort as important to capture the full value of energy storage and other new technologies. In its 2016 IRP Order, the Commission stated on page 23 that:

> In addition, the Commission concurs with the Public Staff's recommendation that in future IRPs the IOUs should evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data. Further, to the extent that these advanced analytics are available at reasonable cost, the IOUs should utilize these resources to provide better information and understanding on optimizing reserve margin needs, as well as overall system operations.

The Commission finds that the proposed ISOP process has the potential to provide those advanced analytic techniques, which can provide better information and understanding on overall system operations. However, the Commission agrees with NCSEA and EDF in that the ISOP process, as outlined in this proceeding, does not have sufficient detail to provide all intervenors and the Commission with an understanding of how exactly it will be implemented in future IRPs.

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Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission requests that the Public Staff work with Duke to select a third party facilitator and convene and facilitate discussions with interested parties on ISOP issues. The Public Staff should file a report with the Commission which summarizes the discussions, agreements reached on particular points, and points on which agreement has not been reached. This report shall be filed in Docket No. E-100, Sub 157, within 270 days of the date of this Order. Additionally, in light of the approaching 2019 IRP Update filing deadline of September 1, 2019, DEC and DEP shall provide a more detailed explanation and tentative timeline for the implementation of the ISOP process in its 2019 IRP Update. Finally, the Commission adopts the Public Staff's recommendation that in future IRPs, the Companies continue to evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data, and to the extent these advanced analytics are available at reasonable cost, utilize these resources to provide better information and understanding on optimizing reserve margin needs, as well as overall system operations.

OTHER IRP MATTERS AND CONCLUSIONS

Quantification of the Value of Fuel Diversity and Risk Analysis

The Public Staff noted that the Comprehensive Risk Analysis used by DENC provides valuable information in trying to identify which least cost portfolio is best in an uncertain world. The Public Staff found that the approach taken by

DENC to analyze the various scenarios with regard to exposure to fuel price volatility scenarios, consideration of rate impacts to customers, and utilizing a probabilistic risk assessment framework provides insightful information to its customers and the Commission. The Public Staff recommended that DEC and DEP develop similar analytical tools to those utilized by DENC, such as the Comprehensive Risk Analysis, to determine the least cost plan that provides the lowest risk to its customers, while also providing operational and compliance flexibility to each utility.

Duke disagreed with the Public Staff's recommendation, noting that it performs sensitivity analyses on multiple variables in future IRPs that are intended to determine the impacts to portfolios when variables are stressed. Duke contends that the sensitivities help mitigate risks of the selected portfolio to the customer.

The Commission recognizes that risk analyses, such as that utilized by DENC, would better inform the Integrated Resource Planning process. Therefore, the Commission finds that DEP and DEC should include in their 2020 IRPs similar probabilistic risk assessment to that of DENC.

Use of Smart Meter Data

The Public Staff indicated that DEC and DEP had indicated that they had not incorporated usage data obtained from smart meters in their load forecasting models. The Public Staff recommended that utilities take advantage of the usage data that is or will become available from their deployments of smart meters and

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include a discussion on how they are using that data to inform their load forecasting, cost of service studies, and improved rate designs.

Duke agreed with the Public Staff smart meter data has the potential to be very informative from a load forecasting perspective and noted the rulemaking on certain data access issues in Docket No. E-100, Sub 161. The Companies also noted the Commission's existing Smart Grid Technology Plan dockets, which provide the Commission and parties with extensive information about smart meters and how DEC and DEP are utilizing this technology and data issues Thus, Duke indicated its belief that additional formal reporting should not be required in the IRP, but that the Companies would update the Public Staff on their progress in incorporating smart meter data into the load forecasting process.

DENC indicated that information about the use of smart meters will also be part of the Company's Grid Transformation Plan, which the Company intends to refile with the VSCC in 2019. DENC noted that its ability to use smart meter data to inform load forecasting, cost of service studies, and rate designs will be limited until it can fully deploy smart meters throughout its service territory, but that it intends to use data from its smart meters to inform these matters when sufficient data is available.

The Commission agrees with the Public Staff that utilities should utilize to the fullest the usage data that is or will become available from their deployments of smart meters. Further, the IOUs should include in future IRPs and Updates a discussion on how they are using that data to inform their load forecasting, cost of service studies, and improved rate designs.

Utility Statement of Need

The Public Staff noted the fundamental link between each IOU's IRP and avoided costs, formalized with the passage of HB 589, which provided that a "future capacity need shall only be avoided in a year where the utility's most recent biennial [IRP] filed with the Commission … has identified a projected capacity need to serve system load…" The Public Staff pointed out that a number of assumptions used by the IOUs in the avoided cost proceeding have not been clearly specified by each utility. To remedy this issue and mitigate the potential for paying for more capacity than what is needed, the Public Staff recommended that the utilities, in their IRP Update to be filed in 2019 and all future IRPs and updates, include a new Utility Statement of Need section. The Public Staff explained that the Utility Statement of Need section will specifically address the link between the first year of capacity need and avoided cost proceeding and specifically address:

1. The year in which the utility would fall below its planning reserve margin without commitment(s) to procure additional resources.

2. Whether QF contracts expiring within the avoided cost term are renewed / replaced in kind, or excluded.

3. Whether utility uprates are solely installed for additional capacity and if they could be considered avoidable.

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4. Whether new EE measures are included in the determination of capacity need.

5. The quantity of MW needed in the first year, and a discussion of whether avoided capacity payments will be made to QF contracts executed in excess of that capacity.

6. The year in which the utility's first avoidable capacity need becomes unavoidable.

7. Whether it is appropriate to create a separate "Avoided Cost Portfolio" in the IRP's portfolio analysis section, which might present a more objective determination of capacity need that could ensure QFs providing capacity are not treated as captive.

The Public Staff explained that this section would then be directly referenced by each utility in its avoided cost proceeding, establishing a clear and well-understood methodology to establish the first year of capacity need for the calculation of avoided capacity payments. The Public Staff contended that the utilities should continue to conduct the foundational analysis of the IRP, with incorporation of the Public Staff's recommendations.

In its reply comments, Duke agreed with the Public Staff's recommendations and stated that it will include a Statement of Need section to more clearly identify the undesignated capacity needs for each utility in DEC's and DEP's 2019 IRP Updates and in future biennial IRP filings.

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The Commission concludes that it should adopt the requirement that the utilities in their 2019 IRP Updates and all future IRPs and updates, include a Statement of Need section specifically addressing the link between the first year of capacity need and their next avoided cost proceeding, containing at a minimum the information specified by the Public Staff.

Retail Rate Impact of Portfolios

The Public Staff noted that an analysis of the rate impacts of each portfolio would inform the comments of intervenors, as well as testimony and comments from the using and consuming public, how changes in generation plans and costs would impact a retail customer, particularly residential customers as to an estimate of the short and long-term costs of the various portfolios. The Public Staff indicated that while there is not currently a statutory or regulatory requirement for Duke to include rate impacts in future IRPs as there is in Virginia,[38] such information could also be useful in other fora, such as the North Carolina Climate Change Interagency Council and the stakeholder workshops formed to facilitate the implementation of Executive Order 80. Therefore, the Public Staff recommended that the Commission require DEC and DEP in future IRPs to evaluate the residential rate impacts of each portfolio evaluated against a no CO_2 scenario and present this information in a manner similar to that used by DENC.

[38] Va. Code § 56-599 B 9 requires DENC to evaluate "[t]he most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations." Accordingly, DENC evaluates the residential rate impact of each Alternative Plan against its Plan A: No CO_2 Tax. This analysis may be found in Section 6.6 of DENC's 2018 IRP filed May 1, 2018.

The Public Staff noted that DENC presents the incremental cost of compliance of each of the Alternative Plans compared to the least cost plan, but due to the significant changes in investment decisions between the filings of the original IRP and its revisions, these estimates are no longer valid. Thus, the Public Staff recommended that DENC submit as a supplemental filing with a recalculated rate impact analysis of the modified Alternative Plans found in its Compliance Filing. DENC requested instead that it be permitted to provide an updated rate impact analysis of the Alternative Plans in its 2019 IRP Update due to be filed by September 1, 2019.

The Commission agrees with the Public Staff that an analysis of the rate impacts of each portfolio would assist the Commission and inform parties and the public how changes in generation plans and costs would impact a retail customer in the short and long-term. As such, the Commission will require DEC and DEP to include an analysis of the retail rate impact of each portfolio similar to that already performed by DENC pursuant to Virginia law. Further, DENC may provide an updated rate impact analysis of the Alternative Plans in its 2019 IRP Update due to be filed by September 1, 2019.

DENC NUGs

The Public Staff noted that some facilities DENC listed as NUGs in Appendix 3B to its IRP are not included in the NUG capacity in Figure 3.1.1.3, while some utility-scale solar facilities are considered as NUG capacity in Figure 3.1.1.3 and others not. The Public Staff also noted that DENC considers all utility-

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scale solar facilities to be behind the meter, but these facilities typically separate the metering of electricity sales from electricity purchases. The Public Staff recommended that in future IRPs, DENC clarify its definition of a NUG facility; use that definition consistently through the IRP; re-evaluate which generating facilities sell energy directly to DENC and identify them separately from facilities that do not; separately identify facilities that sell energy/capacity directly to DENC from facilities that sell directly into PJM; and be consist in references to nameplate rating or equivalent firm capacity rating.

In its reply comments, DENC indicated that it had discussed these recommendations with Public Staff and had agreed to make changes to Appendix 3B and Figure 3.1.1.3 in future full IRPs and to provide an updated version of Appendix 3B as part of the 2019 IRP Update filing to the extent the information is available.

REPS COMPLIANCE PLANS

N.C. Gen. Stat. § 62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and energy efficiency. One megawatt-hour (MWh) of renewable energy, or its thermal equivalent, equates to one renewable energy certificate (REC), which is used to demonstrate compliance. An electric power supplier may comply with the REPS by generating renewable energy at its own facilities, by purchasing bundled renewable energy from a renewable energy facility, or by buying RECs. Alternatively, a supplier may comply by reducing energy consumption through

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implementation of EE measures or electricity demand reduction.[39] The electric public utilities (DEP, DEC, and DENC) may use EE measures to meet up to 25% of their overall requirements in N.C. Gen. Stat. § 62-133.8(b). One MWh of savings from DSM/EE or demand reduction is equivalent to one energy efficiency certificate (EEC), which is a type of REC. All electric power suppliers may obtain RECs from out-of-state sources to satisfy up to 25% of the requirements of N.C. Gen. Stat. §§ 62-133.8(b) and (c), with the exception of DENC, which can use out-of-state RECs to meet its entire requirement. The total amount of renewable energy or EECs that must be provided by an electric power supplier for 2018, 2019, and 2020 is equal to 10% of its North Carolina retail sales for the preceding year.

Commission Rule R8-67(b) provides the requirements for REPS Compliance Plans. Electric public utilities must file their plans on or before September 1 of each year, as part of their IRPs, and explain how they will meet the requirements of N.C. Gen. Stat. §§ 62-133.8(b), (c), (d), (e), and (f). The plans must cover the current year and the next two calendar years, or in this case 2018, 2019, and 2020 (the planning period). An electric power supplier may have its REPS requirements met by a utility compliance aggregator as defined in R8-67(a)(5).

[39] "Electricity demand reduction," as used herein, is defined in N.C. Gen. Stat. § 62-133.8(a)(3a).

Public Staff Comments - REPS Compliance Plans

The Public Staff commented on DEP, DEC, and DENC's plans to comply with N.C. Gen. Stat. §§ 62-133.8(b), (c), and (d), the general[40] and solar energy requirements. The Public Staff also provided consolidated comments on the IOUs' plans to comply with N.C. Gen. Stat. §§ 62-133.8(e) and (f), the swine and poultry waste set-asides.

Public Staff Comments - DEP's REPS Compliance Plans

According to the Public Staff, DEP has contracted for and banked sufficient resources to meet the REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b), (c), and (d). As of December 31, 2017, DEP's compliance services contracts with the Towns of Sharpsburg, Stantonsburg, Black Creek, Lucama, and Winterville terminated, and DEP no longer provides REPS compliance services for any other electric suppliers.

DEP intends to use EE programs to meet 25% of its REPS requirements. A substantial portion of the general requirement will be met by executed purchased power agreements and REC-only purchases from biomass power providers, some of which are combined heat and power (CHP) facilities. Hydroelectric facilities of 10 MW or less, and power generated from landfill gas, will also provide RECs for DEP's retail customers. In addition, DEP plans to continue using solar energy to

[40] The overall REPS requirement of N.C. Gen. Stat. §62-133.8(b), less the requirements of the three set-asides established by N.C. Gen. Stat. §§ 62-133.8(d)-(f), is frequently referred to as the "general requirement."

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help it meet the general requirement. It may also use wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina, to satisfy this requirement.

To meet the solar set-aside, DEP will obtain RECs from its own solar facilities, its residential solar V program, and REC-purchase contracts with other solar PV and solar thermal facilities. DEP is the owner of 140.7 MW of solar facilities that are now operational and available for use to meet a portion of its REPS compliance obligations.[41]

DEP plans to evaluate additional projects through the competitive procurement process established in HB 589. HB 589 allows for competitive procurement of 2,660 MW of additional renewable energy capacity in the Carolinas, with proposals issued over a 45-month period. DEP may develop up to 30% of its required competitive procurement capacity using self-owned facilities.

DEP anticipates that its incremental REPS compliance costs will remain below the cost caps in N.C. Gen. Stat. §§ 62-133.8(h)(3) and (4), but it expects them to rise by approximately 20% over the planning period, reaching approximately 85% of the cost cap in 2020.

[41] *See DD Fayetteville Solar, Inc.*, Docket No. E-2, Subs 1054, 1055, and 1056, Order Transferring Certificate of Public Convenience and Necessity (Dec. 16, 2014); *Duke Energy Progress, Inc.*, Docket No. E-2, Sub 1063, Order Issuing Certificate of Public Convenience and Necessity (Apr. 14, 2015).

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DEP files evaluation, measurement, and verification (EM&V) plans for each EE program in the respective program approval docket.

Public Staff Comments - DEC's REPS Compliance Plans

According to the Public Staff, DEC has contracted for or procured sufficient resources to meet the REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b), (c), and (d) for the planning period, both for itself and for the electric power suppliers for which it is providing REPS compliance services. These suppliers are Rutherford EMC, Blue Ridge EMC, the Town of Dallas, the Town of Forest City, the City of Concord, the Town of Highlands, and the City of Kings Mountain (collectively, DEC's Wholesale Customers). DEC's contractual obligation to provide REPS compliance for the City of Concord and the City of Kings Mountain ended effective December 31, 2018; therefore, these comments reflect REPS compliance services for the City of Concord and the City of Kings Mountain only through 2018.

DEC intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities with a capacity of 10 MW or less and energy allocations from the Southeastern Power Administration (SEPA) will be used to meet up to 30% of the general requirement of DEC's Wholesale Customers.

Hydroelectric facilities of 10 MW or less, together with incremental capacity from the 2012 modifications to DEC's Bridgewater hydroelectric plant, will provide RECs for DEC's retail as well as its wholesale customers. DEC has entered into a contract to sell five of its hydroelectric facilities. All of these facilities intend to register as new renewable energy facilities, so as to retain the option of selling the RECs produced to DEC for REPS compliance purposes.[42]

A substantial portion of DEC's general requirement will be met by purchased power agreements and REC-only purchases from biomass power providers, some of which are CHP facilities. In addition, DEC will continue to use solar energy and power generated from landfill gas to comply with the general requirement. It may also use wind energy, through either REC-only purchases or energy delivered onto its system.

To meet the solar set-aside, DEC will obtain RECs from its self-owned solar PV facilities and from other solar PV and solar thermal facilities. DEC's solar resources include 75 MW of capacity at the Monroe and Mocksville solar facilities, approximately 20 MW from the small distributed solar facilities approved in Docket No. E-7, Sub 856, and 6 MW of anticipated capacity from the Woodleaf facility, which became fully operational in January 2019.

DEC anticipates that its REPS compliance costs will increase, but will be below the cost caps in N.C. Gen. Stat. §§ 62-133.8(h)(3) and (4), for the planning period.

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[42] See *Joint Notice of Transfer, Request for Approval of Certificates of Public Convenience and Necessity, Request for Accounting Order and Request for Declaratory Ruling* filed on July 5, 2018, by DEC, Northbrook Carolina Hydro II, LLC, and Northbrook Tuxedo, LLC in Docket Nos. E-7, Sub 1181, SP-12478, Sub 0, and SP-12479, Sub 0.

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DEC files EM&V plans for each EE program in the respective program approval docket.

Public Staff Comments - DENC's REPS Compliance Plans

According to the Public Staff, DENC has contracted for and banked sufficient resources to meet the REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b) and (c) through 2019 for itself and for the Town of Windsor (Windsor), for which it provides REPS compliance services. DENC has contracted for and banked sufficient resources to meet the REPS requirement of N.C. Gen. Stat. § 62-133.8(d) as well. DENC plans to use EE and purchased RECs to meet the general REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b) and (c) for itself and indicated that it may also use Company generated RECs. For Windsor's general REPS requirement, DENC will use out-of-state wind RECs, in-state biomass and solar RECs, and Windsor's SEPA allocation. For the solar set-aside, DENC plans to purchase in-state and out-of-state solar RECs for itself and Windsor. DENC will rely on out-of-state RECs to meet its compliance requirements, as allowed by N.C. Gen. Stat § 62-133.8(b)(2)(e), but will obtain in-state RECs to meet Windsor's 75% in-state requirement. Its total costs are the same as its incremental costs because, unlike DEC and DEP, it currently plans to purchase only unbundled RECs, rather than RECs that are bundled with renewable electric energy, to meet its REPS requirements.

DENC anticipates that during the planning period, it will incur annual research costs of $50,000 for the continued development of its Microgrid Project.

The Microgrid Project consists of wind, solar and fuel cell energy generation and battery storage at DENC's Kitty Hawk District Office.

DENC expects that the REPS compliance costs for itself and Windsor will be well below the cost caps in N.C. Gen. Stat. §§ 62-133.8(h)(3) and (4) for the planning period.

DENC files EM&V plans for each EE program in the respective program approval docket.

REPS Compliance Summary Tables

The following tables are compiled from data submitted in DEP, DEC, and DENC's Plans. Table 1 shows the projected annual MWh sales on which the utilities' REPS obligations are based. It is important to note that the figures shown for each year are the utilities' MWh sales for the preceding year; for instance, the sales for 2018 are MWh sales for calendar year 2017. The totals are presented in this manner because each utility's REPS obligation is determined as a percentage of its MWh sales for the preceding year. The sales amounts include retail sales of wholesale customers for which the utility is providing REPS compliance reporting and services. Table 2 presents a comparison of the projected annual incremental REPS compliance costs with the utilities' annual cost caps.

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TABLE 1: MWh Sales for <u>Preceding</u> Year

Electric Power Supplier	Compliance Year 2018	2019	2020
DEP	36,829,899	37,521,080	37,685,819
DEC	59,518,351	60,104,379	60,285,246
DENC	4,203,708	4,217,958	4,239,131
TOTAL	100,551,958	101,843,417	102,210,196

TABLE 2: Comparison of Incremental Costs to the Cost Cap

		DEP	DEC	DENC
2018	Incremental Costs	$41,294,711	$27,120,881	$1,052,998
	Cost Cap	$63,874,278	$94,975,829	$5,632,261
	Percent of Cap	65%	29%	19%
2019	Incremental Costs	$47,421,825	$36,738,176	$1,224,857
	Cost Cap	$64,583,052	$93,929,320	$5,288,797
	Percent of Cap	73%	39%	23%
2020	Incremental Costs	$55,445,392	$48,524,154	$1,419,320
	Cost Cap	$65,271,008	$94,623,837	$5,304,517
	Percent of Cap	85%	51%	27%

Swine Waste and Poultry Waste Set-Asides

N.C. Gen. Stat. § 62-133.8(a) provides that in 2012 at least 0.02% of the electric power sold to customers should be produced from swine waste, and this percentage increases to 0.14% by 2015 and 0.20% by 2018. Subsection (f) provides that in 2012 at least 170,000 MWh of power sold to retail customers will be generated from poultry waste, and that this requirement will increase to 700,000 MWh in 2013 and 900,000 MWh in 2014.

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In every year from 2012 through 2017, the electric suppliers moved that the swine waste requirement be delayed until the following year, and the Commission granted their requests. In 2018, they moved that the requirement be set at 0.02% for the electric public utilities and zero for the EMCs and municipalities, and this request likewise was granted.

With respect to poultry waste, the electric suppliers moved in 2012 and again in 2013 to delay the 170,000-MWh annual requirement for a year, and the Commission granted their motions. The Commission's 2013 order set the requirement at 170,000 MWh for 2014 and 700,000 MWh for 2015. The electric suppliers were able to meet the 170,000-MWh requirement in 2014, but they could not comply with the increase to 700,000 MWh for 2015. In that year, and again in 2016 and 2017, they moved that the poultry waste requirement be kept at 170,000 MWh, and their motions were granted. In their 2018 motion, the electric suppliers proposed that the poultry waste requirement be set at 300,000 MWh, and the Commission approved their proposal.

In its annual orders granting delays or reductions in the swine and poultry waste requirements, the Commission has also required the electric power suppliers to file reports describing the state of their compliance with the set-asides and their negotiations with the developers of swine and poultry waste-to-energy projects, initially on a tri-annual basis and now semiannually. These reports are filed confidentially in Docket No. E-100, Sub 113A. The Commission has further required the electric power suppliers to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities. Additionally, the Commission has directed the Public Staff to hold periodic stakeholder meetings to facilitate compliance with the swine and poultry waste set-asides. In response, the Public Staff organized a stakeholder meeting held on June 23, 2014, and eight subsequent occasions. The attendees have included farmers, the North Carolina Pork Council, the North Carolina Poultry Federation, waste-to-energy developers, bankers, state environmental regulators, and the electric power suppliers. The meetings allow the stakeholders to network and voice their concerns to the other parties. Due to advancements in compliance, all parties agreed that semiannual meetings were no longer necessary and requested that they only be held yearly. The Commission granted this request in its 2017 order.

Up to now, the State's electric power suppliers have been able to comply only to a limited extent with the poultry waste set-aside requirement, and to an even lesser extent with the swine waste requirement. Nevertheless, the REPS statute has served as a stimulus for several important advances in waste-to-energy technology.

First, several swine farms have installed anaerobic digesters at their swine waste lagoons and have produced biogas that has been used as fuel to operate small electric generators at these farms. Electric power suppliers have purchased the electricity produced by these generators – or, alternatively, have purchased

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the RECs when the electricity was used on the farm where it was generated – and this represented the initial step toward compliance with the swine waste set-aside.

Second, poultry waste has been transported by truck to existing and new generation facilities, where it has been co-fired with wood or other fuels.

Third, there has been progress in the development of large centralized anaerobic digestion plants in areas where numerous swine farms are located. These plants receive swine waste from numerous sources, produce biogas from the waste by the digestion process, and eliminate impurities from the biogas so that it meets quality standards and is eligible to be injected into the natural gas pipeline system. A specified amount of this biogas, which is referred to as “directed biogas” or “renewable natural gas,” is injected into a pipeline, and an equivalent amount of natural gas is delivered by the pipeline operator to a gas-fired electric generating plant. These directed biogas facilities were first built in Midwestern states with extensive swine farming activity, but on December 2, 2016, Carbon Cycle Energy, LLC, began construction of a directed biogas facility in Warsaw, North Carolina.[43]

Four days after the start of construction at the Carbon Cycle facility, Piedmont Natural Gas Company, Inc., petitioned the Commission for approval of

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[43] *See Order Accepting Registration of New Renewable Energy Facilities,* Docket No. E-7, Subs 1086 and 1087 (Mar. 11, 2016). In this docket, DEC stated that it had entered into contracts to purchase directed biogas from High Plains Bioenergy, LLC, in Oklahoma, and Roeslein Alternative Energy of Missouri, LLC. On March 18, 2016, DEC supplemented its registration statement to indicate that it also entered into contracts to purchase directed biogas from Carbon Cycle Energy for nomination to its Buck Combined Cycle Station.

a new Appendix F to its service regulations, authorizing the company to accept "Alternative Gas" (which includes, subject to various restrictions, biogas, biomethane, and landfill gas) onto its system and deliver it to purchasers. In an order issued on June 19, 2018, the Commission approved Piedmont's proposed appendix and established a three-year pilot program to implement it. The Commission has authorized four firms – C2E Renewables NC, Optima KV, LLC, Optima TH, LLC, and Catawba Biogas, LLC – to participate in the pilot program, and two additional firms, GESS International North Carolina, Inc., and Foothills Renewables LLC, have filed applications to participate.

In March of 2018, Optima KV completed its interconnection to the Piedmont Natural Gas system and began delivering biogas to DEP's Smith Energy Complex in Hamlet, North Carolina. The Optima KV facility thus became the first operational directed biogas facility in North Carolina.

The Public Staff states that the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides. However, they have made substantial progress toward complying with these difficult obligations, and as advances in waste processing technology are made, they may be able to achieve full compliance with the statutory requirements in the not too distant future. The supplier best positioned to reach full compliance is DENC, since it can obtain all of its RECs from out-of-state. Indeed, DENC's compliance plan indicates that already "both DENC and the Town of Windsor have sufficient RECs in [NC-RETS] to meet the 2018-2020 requirements" for swine waste. DENC does not express

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quite as high a degree of certainty about its compliance with the poultry waste set-aside, given the possibility that between now and 2020 some of its suppliers may default on their contracts; however, it does state that its efforts have "yielded multiple poultry waste REC contracts and sufficient delivered volume to comply with both the Company's and Town of Windsor's out-of-state requirements for years 2018, 2019 and 2020."

Public Staff Conclusions - REPS Compliance Plans

In summary, the Public Staff concluded that:

1. Overall, the electric public utilities believe they are in a better position to comply with all of the requirements of the REPS, including the set-asides, than in previous years.
2. DEC, DEP, and DENC should be able to meet their REPS obligations during the planning period, with the exception of the swine and poultry waste set-asides, without nearing or exceeding their cost caps; however, DEP may approach the caps in 2020.
3. All three utilities should be able to meet the swine and poultry waste requirements in 2018, after the issuance of the Commission's order of October 8, 2018, reducing the requirements.
4. DEC and DEP indicated in their REPS compliance plans that they could comply with the poultry waste set-aside in 2018, and DEC stated that it could meet the swine waste requirement as well; but both companies indicated that compliance would deplete their supply of swine and

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poultry RECs so severely that they could not comply in 2019 and 2020. Both subsequently joined in the electric suppliers' motion to reduce the swine and poultry requirements for 2018, and their motion was granted. However, the fact that DEC and DEP were even able to consider the possibility of compliance in 2018 represents progress in comparison with previous years.

5. DENC expects to meet the swine waste requirements for 2018 through 2020, both for itself and the Town of Windsor, and it is confident, although not certain, that it will also meet the poultry waste requirement for all three years of the planning period.
6. DEC and DEP are actively seeking energy and RECs to meet the set-aside requirements for the years in which they expect to fall short of compliance. DENC is also seeking to acquire RECs and thus strengthen its position for compliance with the swine and poultry requirements in future years.
7. The Commission should approve the 2018 REPS Compliance Plans filed by DEC, DEP, and DENC.

Commission Conclusions - REPS Compliance Plans

The Commission concludes that the REPS Compliance Plans filed by the utilities contain the information required by Commission Rule R8-67(b). As such, and based on the recommendation of the Public Staff, the Commission accepts the REPS Compliance Plans filed in this docket.

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COMMISSION CLOSING COMMENTS

Integrated Resource Planning is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. Potential significant regulatory changes, particularly at the federal level, and evolving marketplace conditions create additional challenges for already detailed, technical, and data-driven IRP processes. The Commission finds the IRP processes employed by the utilities to be both compliant with State law and reasonable for planning purposes in the present docket. The Commission recognizes that the IRP process continues to evolve. The comments, findings, conclusions, and Commission directives included in this Order are intended to inform and guide the electric utilities and parties in their ongoing IRP processes and participation.

IT IS, THEREFORE, ORDERED, as follows:

1. That this Order shall be, and is hereby, adopted as part of the Commission's current analysis and plan for the expansion of facilities to meet future requirements for electricity for North Carolina pursuant to N.C. Gen. Stat. § 62-110.1(c).

2. That the IOUs' forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable for planning purposes, and the Commission accepts the IRP Reports as filed in this docket.

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3. That the 2018 REPS compliance plans filed by the IOUs are hereby accepted.

4. That the IOUs, in the preparation of future IRPs, shall adhere to the conclusions and directives of the Commission documented in the body of this Order.

5. That the IOUs, in the preparation of future IRPs, shall include a Statement of Need, including at a minimum the information proposed by the Public Staff, which shall be used to establish the first year of capacity need for future avoided cost proceedings.

6. That pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP shall continue to pursue least-cost Integrated Resource Planning and file separate IRPs until otherwise required or allowed to do so by Commission order, or until a combination of the utilities is approved by the Commission.

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of _________, 2019

NORTH CAROLINA UTILITIES COMMISSION

Janice Fulmore, Deputy Chief Clerk