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Review and Evaluation of the Peak Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans

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Prepared on behalf of Natural Resources Defense Council, Southern Alliance for Clean Energy, and the Sierra Club

February 17, 2017

I. INTRODUCTION

1. Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC") filed their 2016 Integrated Resource Plans ("2016 IRP") on September 1, 2016 in Docket No. E-100 Sub 147. The peak load forecasts and reserve margins serve as the basis for each utility's determination of the total generating capacity required over the IRP planning horizon. This report evaluates the peak load forecasts used in the 2016 IRPs. The determination of the reserve margins used in the 2016 IRPs is the subject of a separate Wilson Energy Economics report ("Reserve Margin Report").

II. PEAK LOAD FORECASTING METHODOLOGY

2. The 2016 DEC and DEP IRPs include peak load and energy forecasts for the respective service territories over the 2017 to 2031 time period. The forecasts encompass residential, commercial and industrial retail customers and also wholesale customer loads. The companies use econometric models to forecast the residential, commercial and industrial customer classes separately. The forecasts rely upon economic and demographic projections from Moody's Analytics, and projections of appliance efficiencies and saturations from Itron, based on U.S. Energy Information Administration data.

3. In recent years peak load growth has been weak across most of the country, and forecasts are generally being revised downward. The weak growth is partly due to the economic downturn and weak recovery over the past decade. However, there are also trends toward more efficient use of electricity, and a weaker relationship

between economic growth and load growth. For example, PJM Interconnection, LLC, which prepares peak load forecasts for all or part of 13 states (including North Carolina) and the District of Columbia, has been continually enhancing its load forecasting methodology, and its most recent forecasts have again been sharply reduced.[1]

III. COMPARISONS OF PEAK LOAD FORECASTS TO RECENT TRENDS

4. This evaluation begins with a review of the actual and weather-adjusted summer and winter peak load trends. Actual peak loads will tend to vary substantially from year to year, reflecting the presence or absence of the type of extremely hot or cold weather than can cause the highest summer or winter peak loads, respectively. Weather-adjusted peak loads are estimates of what the peak load would have been in a historical period had the peak occurred on a day with the typical peak-causing weather. Weather-adjusted historical peak loads remove the impact of weather variability, and reveal the underlying peak load trend due to other factors such as economic and demographic trends, changes in industry and end-use technologies, and energy efficiency.

5. Peak load forecasts are generally considered median or 50-50 forecasts (meaning that the forecasters consider the actual future peak load to be equally likely to exceed, or to fall short of, the forecast value) or mean forecasts (averages or expected values of the future peaks). Similarly, a weather-adjusted historical peak is generally also considered a median value for the past period (a value that, based on actual weather, had a 50-50 chance of being exceeded) or perhaps a mean value. Thus, the weather-adjusted actual peaks correspond to what the peak load forecasts are attempting to estimate. Peak load forecasts can be compared to the trends in weather-adjusted historical peaks, and we should expect the forecasts to be generally consistent with those trends. Therefore, a comparison of a peak load forecast to the

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[1] PJM, *PJM Load Forecast Report, January 2017* (noting at p. 2 that the forecast for 2020 has been reduced two percent compared to the prior forecast prepared one year earlier).

corresponding weather-adjusted peak load trend is a useful starting point for evaluating the reasonableness of a forecast.

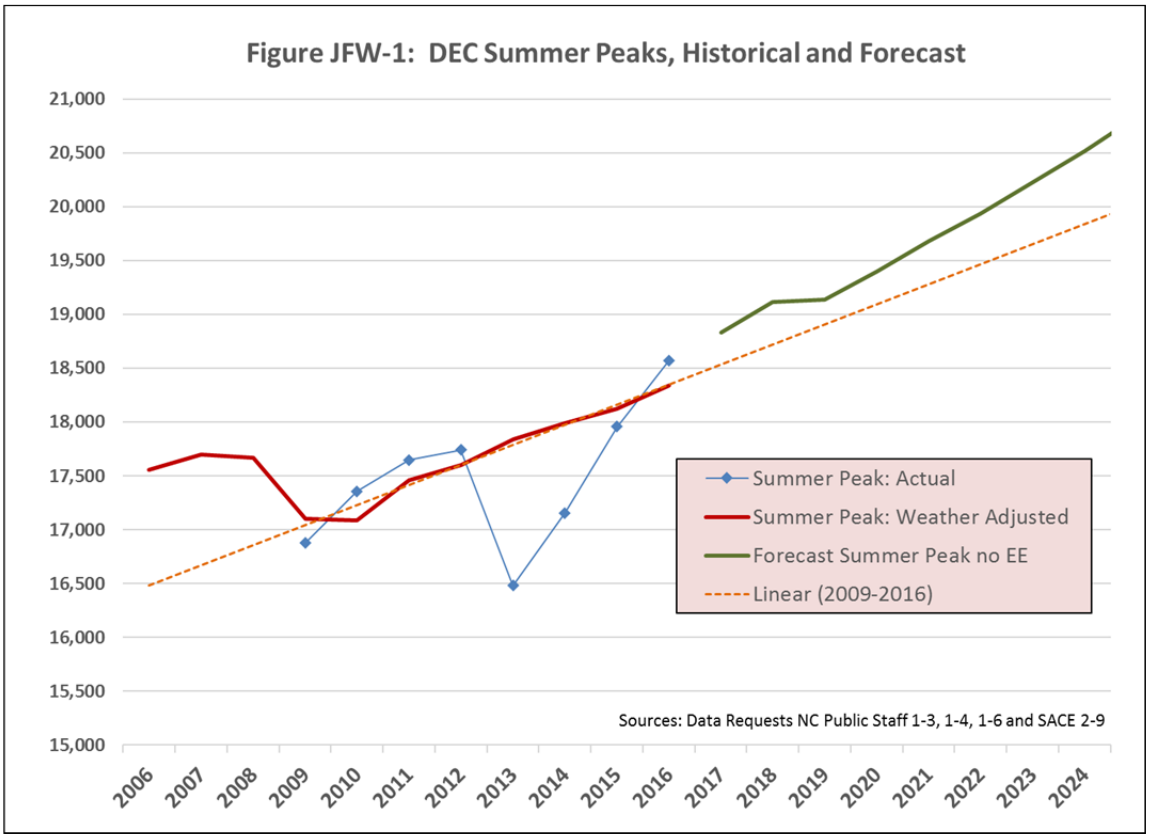
6. However, for a meaningful comparison of trends in weather-adjusted peaks to forecast peaks, both sets of data must represent roughly the same underlying loads. For example, the obligations under a large new wholesale contract would not be reflected in the historical trends but might be included in the forecast, and this would cause the forecast to appear high compared to the historical trend unless the impact of the contract is taken into account.

7. In addition, anticipated shifts in the underlying economic, demographic or technological trends that drive peak load growth could cause the peak forecast to deviate from the historical trend. For example, economic growth is a driver of peak load growth, and if economic growth is expected to be stronger over the forecast period than it has been in recent years, this could cause the forecast to increase more rapidly than the trend, other things equal. Similarly, improvements in energy efficiency affect peak load growth, so changing trends in this regard can also cause a forecast to deviate from past trends.

8. DEC and DEP provided summer and winter peak load forecasts (response to Public Staff data request 1-7) both with and without the load-reducing impacts of future energy efficiency program implementation (discussed in DEC 2016 IRP, pp. 9-10). This report's comparisons will be based on the peak load forecasts without the forecast impacts of the future implementation of these programs, whose additional impacts are in any case rather small in the first years of the forecast. It should be noted that the forecasts without the future energy efficiency implementations will still reflect the future impacts of prior energy efficiency implementation. DEC and DEP also provided historical actual and weather-adjusted peak loads (responses to SACE DEP 2-9, SACE DEC 2-9, Public Staff DEC 1-3, DEC 1-4, DEP 1-3, DEP 1-4).

IV. PEAK LOAD FORECASTS COMPARED TO RECENT TRENDS: DEC

9. Figure JFW-1 compares recent DEC actual and weather-adjusted historical summer peak loads to the forecast peaks. The figure also shows a trend line based on the weather-adjusted peaks over the 2009 to 2016 period, during which period they exhibited a quite steady trend.



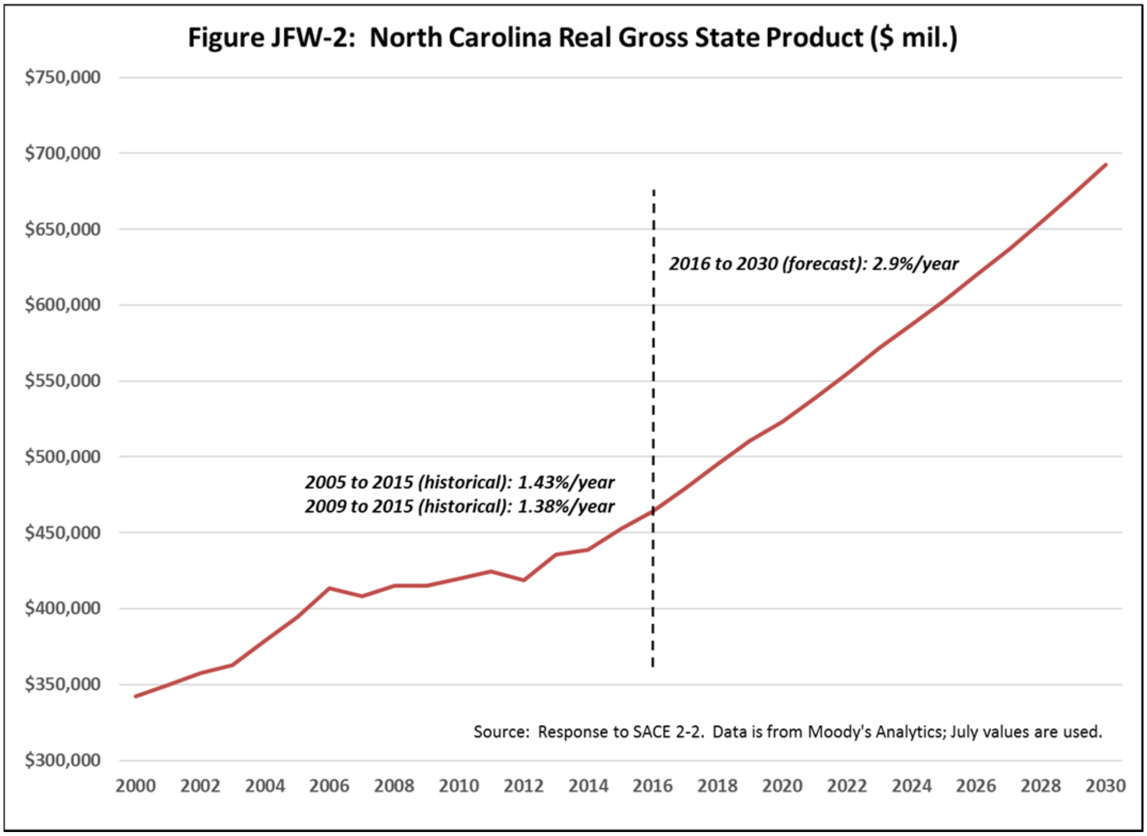
10. The peak load forecast reflects some changes in DEC's wholesale sales contracts over time, documented in DEC 2016 IRP, Table H-1. The cumulative total change in such contracts is [redacted], so the composition of the peak load forecast in that year is quite [redacted] the historical trend. Figure JFW-1 suggests that the forecast is roughly 200 MW, or about 1%, in excess of the trend in 2019, and that after 2019 the forecast peaks grow at a somewhat faster rate.

11. However, in a recent supplemental response to a data request, DEC also states that the forecast reflects 540 MW of a backstand agreement with North Carolina Electric Membership Corporation ("NCEMC"), and that this would not be reflected in the historical values except when the Catawba Nuclear Station was not in operation (responses and follow-up responses to Data Requests SACE 3-2 and 3-3). [redacted] If indeed this 540 MW is included in the forecast and is not reflected in the historical data, it is appropriate to adjust the forecast downward by this amount for comparison purposes, in which case the forecast would lie somewhat below the trend line for most of the forecast period.

12. Further, if this 540 MW obligation, which apparently is unlikely to be called upon, was included in the forecast, the forecast can no longer be considered a median or mean forecast. This has implications for the use of the forecast in the resource adequacy study, as discussed in the Reserve Margin Report.

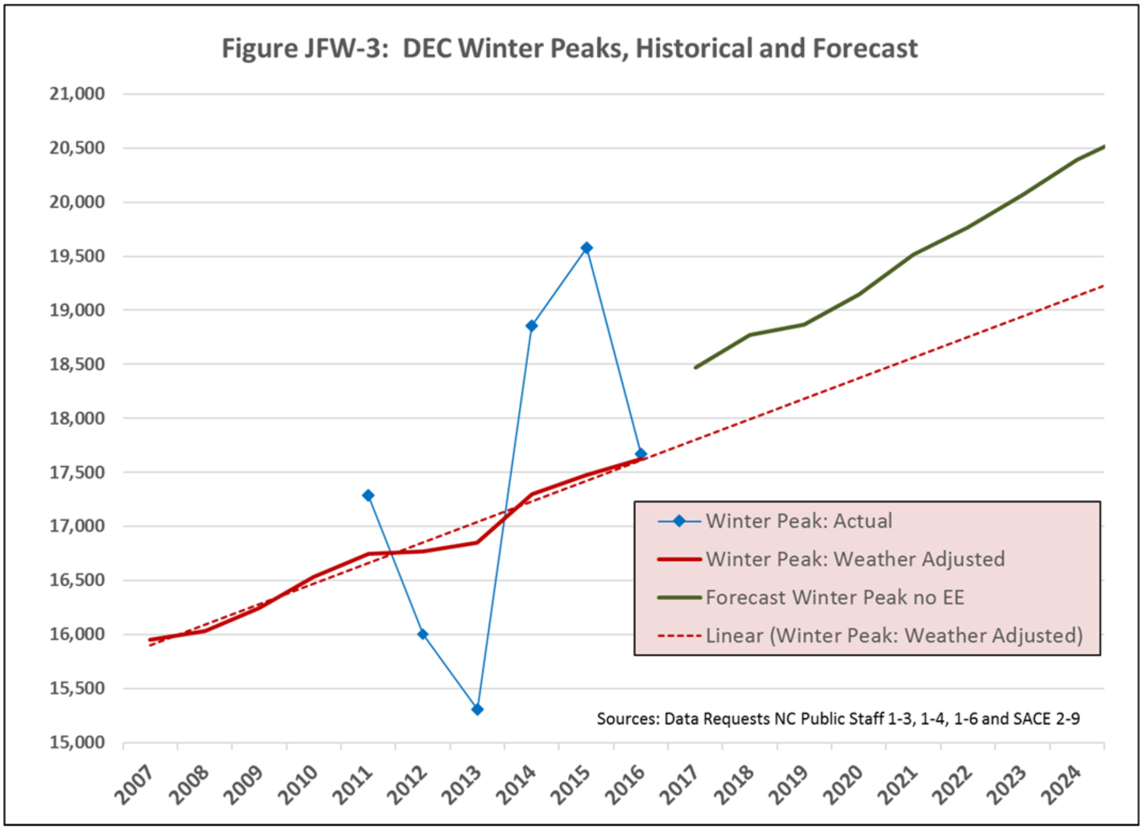
13. In addition, DEC's peak load forecasts are based on economic forecasts that anticipate faster growth in the North Carolina economy over the coming years than was seen in the past decade. Figure JFW-2 shows the North Carolina Gross State Product ("NC GSP") forecast used to prepare the load forecasts, from Moody's Analytics. As shown in the figure, the North Carolina economy grew at about a 1.4% per year rate during 2009 to 2015, while the forecast rate of growth is 2.9% per year. This would help to explain the somewhat faster rate of growth in the peak load forecast compared to trend.

14. The load forecasts also use historical and projected appliance saturation and penetration data from Itron and the U.S. Energy Information Administration (DEC 2016 IRP, p. 16). While I have not performed a detailed review of this data, some key indicators, such as central air conditioner efficiency, suggest a slowing rate of improvement in energy efficiency over the coming years compared to recent trends.



15. Overall, DEC's summer peak load forecast appears with a reasonable range, especially if it is correct that the 540 MW NCEMC backstand agreement is included in the forecast but not reflected in the historical data.

16. Turning now to DEC's winter peak load forecast, Figure JFW-3 presents the comparison to recent actual and weather-adjusted peaks. Figure JFW-3 also shows the very high actual winter peak loads seen in 2014 and 2015, which occurred under conditions of very extreme cold. As noted in the discussion of summer peaks, the forecast reflects changes in wholesale contracts documented in DEC 2016 IRP Table H-1, and the cumulative change is [redacted], so that year is perhaps the best to focus on for comparison purposes. The winter peak forecast is roughly 700 MW in excess of trend in 2019. The 540 MW NCEMC backstand agreement, noted above, would explain most of that discrepancy, if indeed it is included in the forecast but not reflected in the historical data. Anticipated stronger economic growth would also help to explain the discrepancy.



17. Figure JFW-4 shows the hourly load patterns on the two highest winter peak load days of 2014 and of 2015, based on the hourly data provided in response to data request SACE 2-8[2]. The lowest temperatures on these days (under 10 degrees) had not occurred for nearly twenty years, since 1996 (based on the hourly temperature data provided in the response to SACE 2-16). Note also that the highest loads on these days occurred for only a very brief period around 8 AM. Changes in end-use technologies may be affecting these brief, extreme winter peak loads under extreme cold conditions. However, DEC states that it has not performed any formal analysis to determine which end uses are contributing to these load spikes on extremely cold winter mornings (response to Data Request SACE 2-11).

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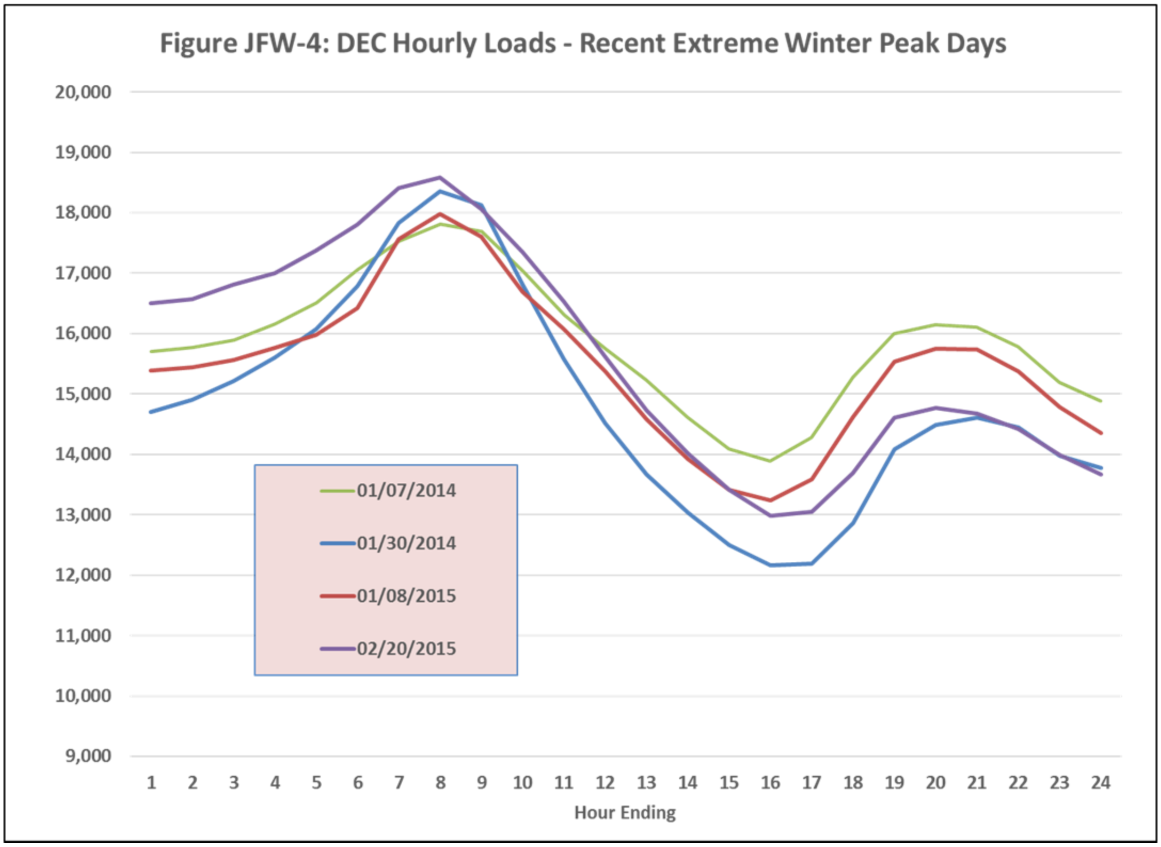
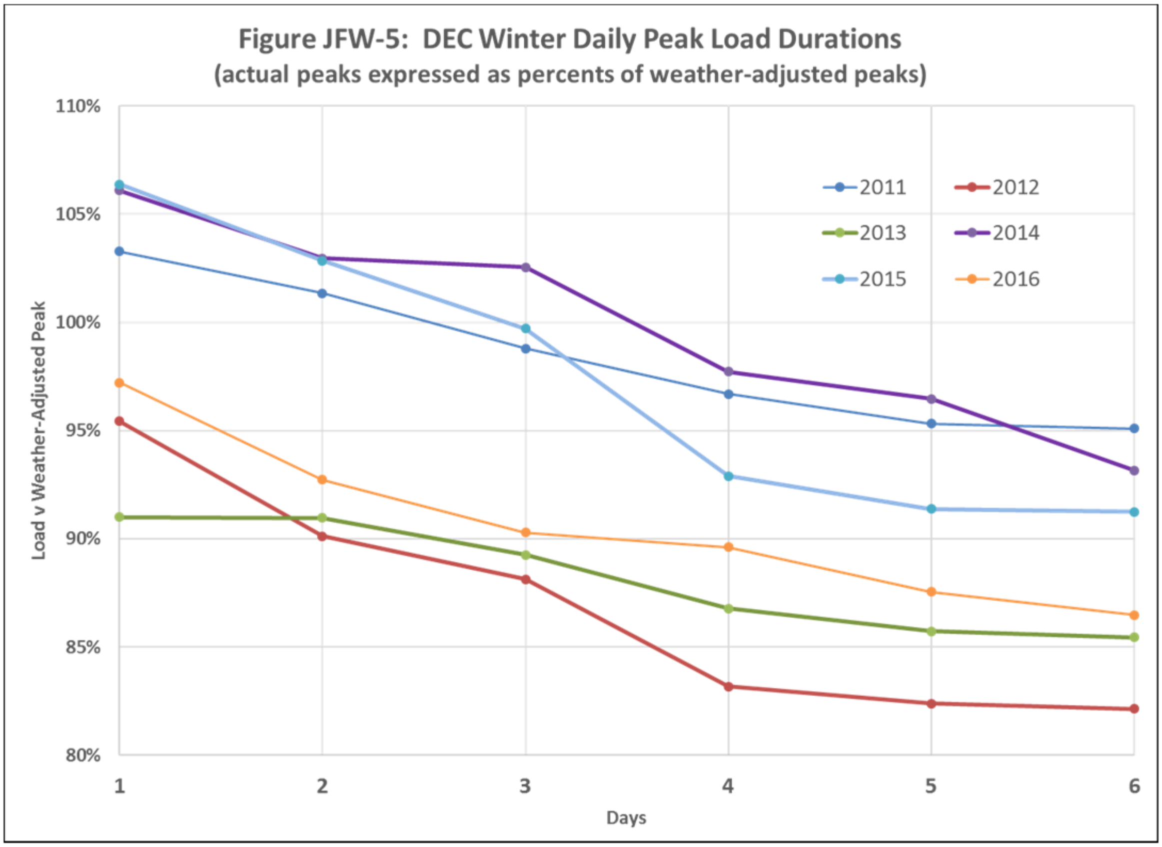
[2] It should be noted that there were some quite substantial differences between the summer and winter actual peak loads for 2014 to 2016 as reported in the responses to data requests Public Staff 1-3 and 1-4 and the hourly historical data provided in response to SACE 2-8. Figures JFW-4 and JFW-5 rely upon the hourly data.



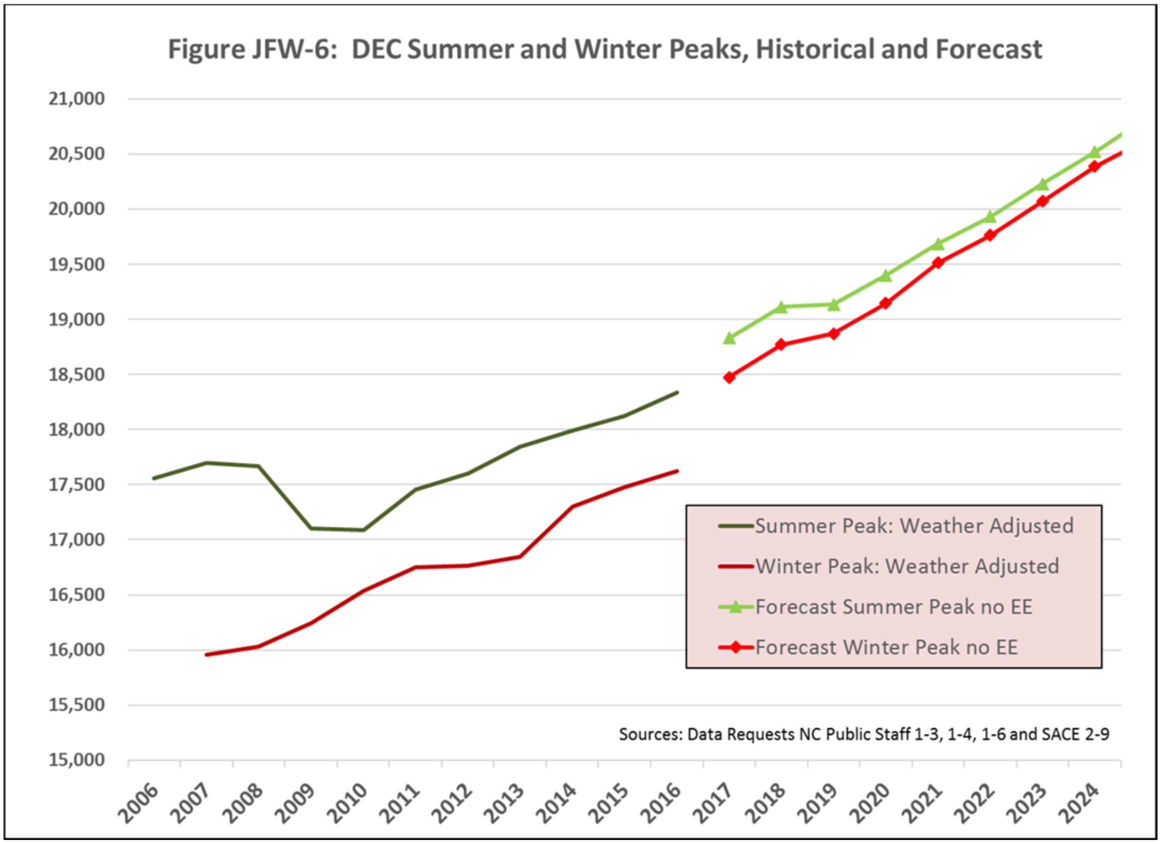
18. Note also that the extreme winter loads occurred for a brief period of time, and only on a few extremely cold winter days. Figure JFW-5 shows the daily peaks on the highest winter load days, expressed as a percent of the annual weather-adjusted peak, for the top six peak winter days in each of the past six years. As could be expected, three years had peaks above the weather-adjusted peak and three had peaks below that level. However, even in the "polar vortex" year (2014), the fourth highest daily peak that winter was far below the highest peak, and also below that year's weather-adjusted peak. So while there may be indications that winter peak loads can exhibit brief, extraordinary spikes on days with extremely low temperatures that are rarely seen, this should not result in a substantial increase in a peak load forecast that is intended to be a median or mean peak load forecast.

19. Overall, the DEC winter peak forecast seems somewhat high compared to the trend in the weather-adjusted peaks, even if it is appropriate to adjust it by 540 MW for the NCEMC backstand agreement. While the extreme winter peak loads in 2014 and



2015 suggest that changes in end uses may be contributing to higher winter peak loads under extreme cold, this may be a phenomenon that only has large impacts under very extreme conditions that occur very infrequently. It is not clear that under the very cold, but less extreme temperatures typical of the annual winter peak day in most years that such extreme loads should be expected. And again, if the 540 MW for the backstand agreement has been added, this is no longer a median or mean forecast.

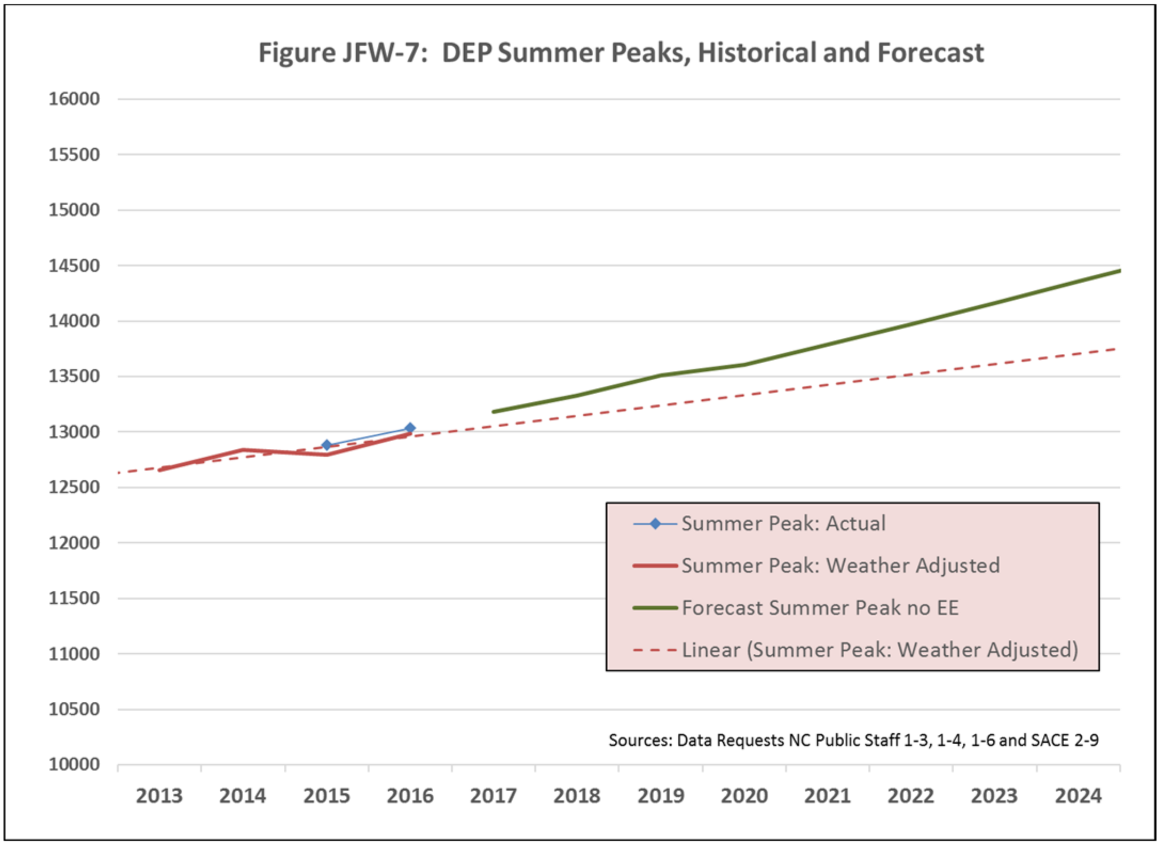
20. Figure JFW-6 shows the DEC winter and summer peak load history and forecast on the same graph. There has been a steady differential between the weather-adjusted summer and winter peaks during recent years, averaging 750 MW over 2009 to 2016, and averaging 683 MW over 2014 to 2016. The forecast breaks from this pattern, again suggesting that the winter peak forecast is high.



V. PEAK LOAD FORECASTS COMPARED TO RECENT TRENDS: DEP

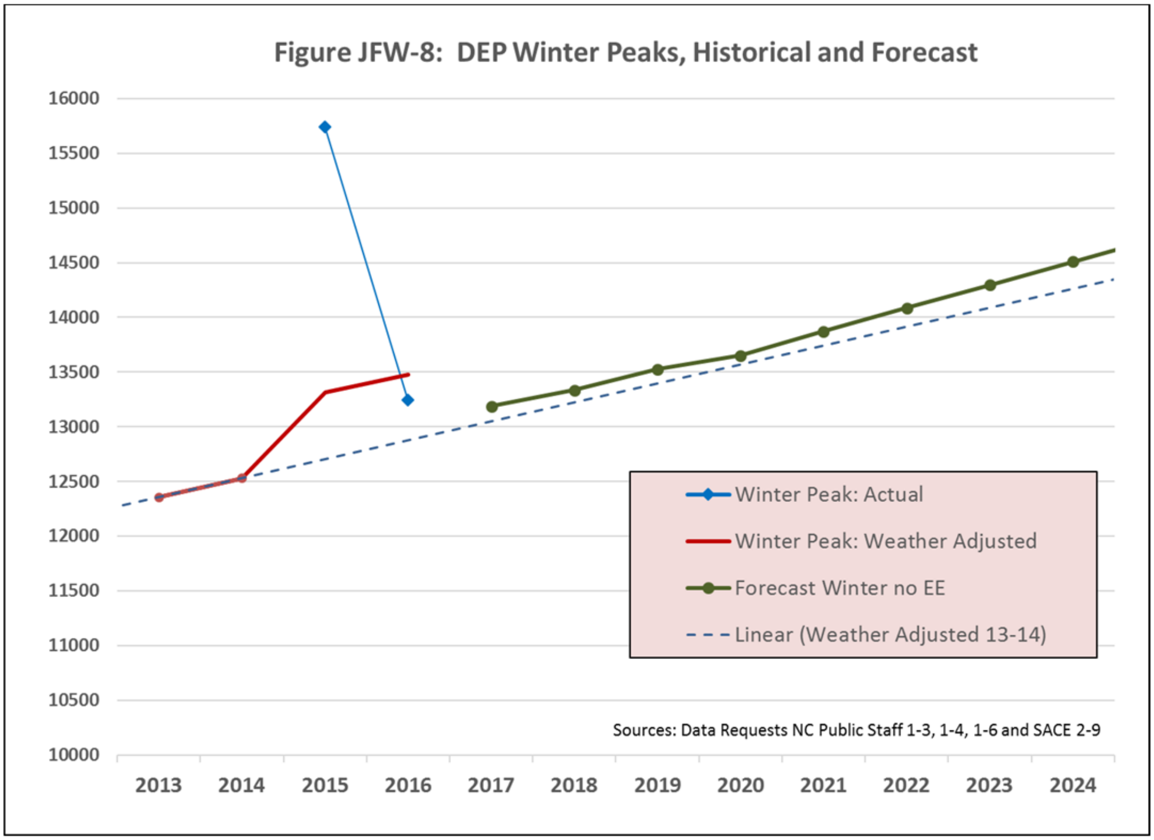
21. Figures JFW-7, JFW-8 and JFW-9 compare recent DEP actual and weather-adjusted historical summer peak loads to the forecast peaks. However, in contrast to the DEC data, very little historical data was provided for DEP, making it difficult to discern past trends. Figure JFW-7 shows a trend line based on the weather-adjusted peaks over the 2013 to 2016 period, during which period they exhibited a rather steady trend. As for DEC, there were changes in the DEP wholesale sales contracts documented in DEP 2016 IRP, Table H-1. The cumulative total change is [redacted], and [redacted], so the peak load forecast in 2020 is quite comparable to the historical trend. Figure JFW-7 suggests that the forecast is roughly 200 MW in excess of the trend in 2020. After 2020 the forecast peaks grow at a faster

rate than the trend, which may be explained by the anticipated faster economic growth discussed earlier.



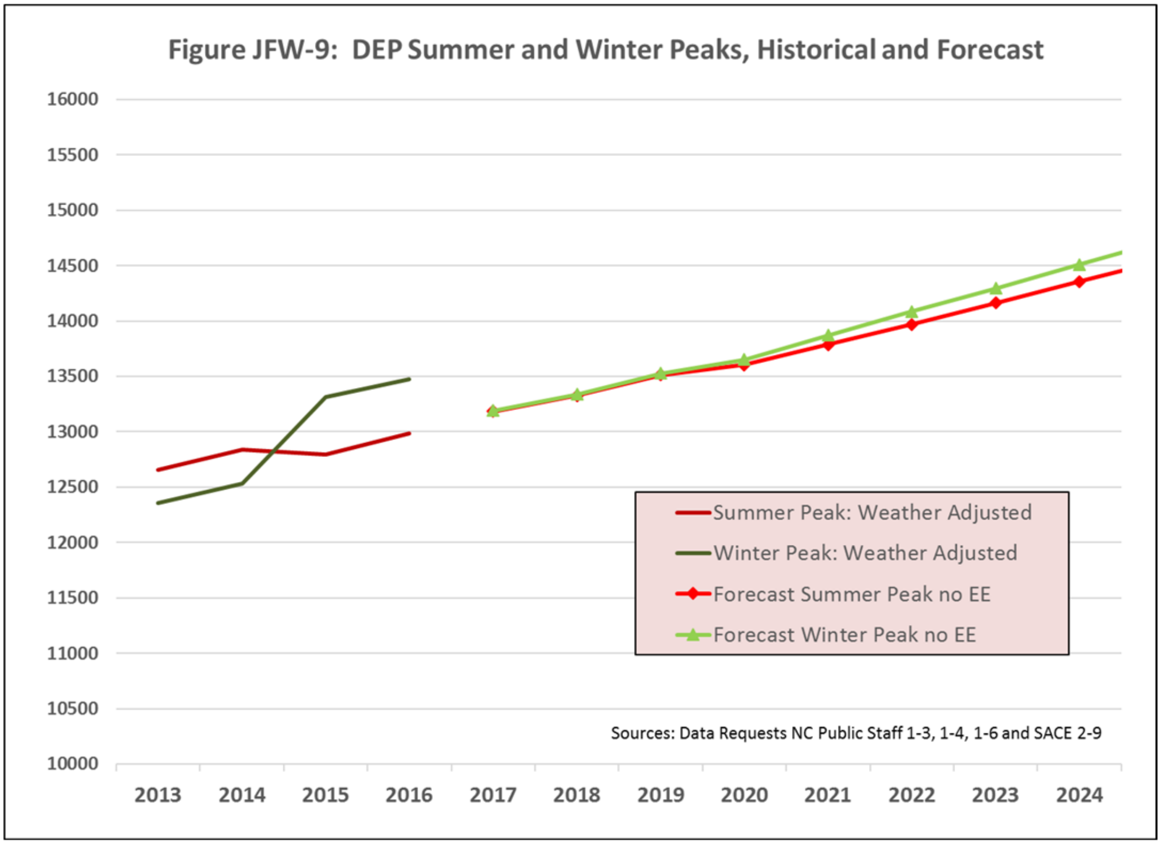
22. Figure JFW-8 presents DEP's winter peak forecast and the available historical data. The forecast is rather consistent with a trend line based on the 2013 and 2014 winter peaks. The actual peaks were considerably higher in the winters of 2015 and 2016, due to the extreme cold noted above. The weather-adjusted peak values that were provided for 2015 and 2016 were also considerably higher than the values for 2013 and 2014, which may reflect that the methodology for determining weather-adjusted peaks does not fully compensate for weather impacts, and the weather-adjusted values for 2015 and 2016 may be overstated. In responses to data requests (SACE 3-2 and 3-3d) DEP stated that the 2016 actual results were not available when the forecast was prepared, and also suggested that its forecasting model may discount such

extraordinary growth, such that the forecast tends to reflect the earlier trends. DEP also suggested that future winter peak forecasts may be higher.



23. Again, the possibility of extreme loads under very rare extreme temperatures might not result in much increase in a peak load forecast that is intended to be a median or mean forecast.

24. Figure JFW-9 presents the DEP summer and winter peak load forecasts and history together. As with DEC, the relationship between the summer and winter peaks reflected in the historical data (at least as reflected for 2013-2014) is changed in the forecast, with the winter peak having risen faster than the summer peak. Due to the lack of sufficient historical data to establish trends, and the lack of support for a substantial increase in the winter peak load forecast, this report draws no conclusion with regard to the reasonableness of the DEP peak load forecasts.



VI. SUMMARY AND RECOMMENDATIONS

25. To summarize the observations with regard to the peak load forecasts:

a. DEC's summer peak load forecast falls within a reasonable range, especially if it includes the 540 MW NCEMC backstand agreement that is not reflected in the historical data.

b. DEC's winter peak load forecast seems somewhat high, even considering the NCEMC backstand agreement.

c. There is insufficient information to come to a conclusion about the DEP peak load forecasts.

26. The very high loads that have occurred on recent, extremely cold winter days occur for very few days and hours; loads in other hours and on other days are much lower. Peak load forecasts intended to represent median or mean values should be relatively unaffected by such rare events.

27. If the DEC peak load forecasts include the 540 MW NCEMC backstand agreement that is rarely invoked, they are no longer median or 50-50 peak load forecasts; nor do they represent an average or mean of the possible peak values. This has implications for how the forecasts are used to evaluate resource adequacy and determine capacity needs as discussed in the Reserve Margin Report.

28. Finally, this evaluation leads to the following suggestions for future IRP proceedings:

a. The companies should research the drivers of load spikes on extremely cold winter mornings.
b. Future IRP filings should more clearly document wholesale contract arrangements and how they are reflected in the forecasts and in the historical load data. The forecasts for the various wholesale arrangements should be provided separately from the utility load forecasts.
c. The IRP filings should clearly specify whether the peak load forecasts are intended to be median or mean forecasts, or what portion of the forecast (such as, net of wholesale contracts) is intended to be a median or mean value.
d. The IRP filings would also benefit from data and explanation of how the forecasts are or are not consistent with recent trends in actual and weather-adjusted peak loads.

APPENDIX: QUALIFICATIONS OF JAMES F. WILSON

James F. Wilson is an economist and independent consultant doing business as Wilson Energy Economics, with a business address of 4800 Hampden Lane Suite 200, Bethesda, Maryland 20814. Mr. Wilson has over 30 years of consulting experience, primarily in the electric power and natural gas industries. Many of his consulting assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. His experience and qualifications are further detailed in his CV, available at www.wilsonenec.com.

Review and Evaluation of the Reserve Margin Determinations for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans

James F. Wilson, Wilson Energy Economics

Prepared on behalf of Natural Resources Defense Council, Southern Alliance for Clean Energy, and the Sierra Club

February 17, 2017

I. INTRODUCTION

1. Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC") filed their 2016 Integrated Resource Plans ("2016 IRP") on September 1, 2016 in Docket No. E-100 Sub 147. The peak load forecasts and reserve margins serve as the basis for each utility's determination of the total generating capacity required over the IRP planning horizon. The reserve margins used in the 2016 IRPs were based upon recommendations in the DEC and DEP 2016 Resource Adequacy Studies, November 17, 2016 ("DEC RA Study", "DEP RA Study") prepared by Astrape Consulting and provided in response to data request SACE 1-8. This report evaluates the adopted reserve margins and the RA Studies that are the basis for the adopted reserve margins. The load forecasts used in the 2016 IRPs are the subject of a separate Wilson Energy Economics report ("Load Forecast Report").

II. THE 2016 RESOURCE ADEQUACY STUDIES: OVERVIEW AND RECOMMENDATION

2. The DEC and DEP RA Studies both recommend a 15% installed reserve margin relative to summer peak demand, which provides a 17% winter installed reserve margin (DEC RA Study pp. 6-7). This is an increase from the 14.5% installed reserve margin relative to summer peak demand recommended in similar resource adequacy studies in 2012 and reflected in prior IRPs. According to both RA Studies (p. 2), the increase in the recommend reserve margins reflects "A re-evaluation of seasonal risk after the Polar Vortex in 2014 and cold weather during 2015 resulted in a significant shift to winter reliability issues."

3. The RA Studies document a probabilistic simulation of load and resources to find the planning reserve margin required to satisfy a “one day in ten years” resource adequacy criterion, equivalent to an annual Loss of Load Expectation (“LOLE”) of 0.1. In addition to this analysis of “physical reliability”, the RA Studies also include evaluations of “economic reliability”, and a preliminary review of the assumptions underlying this economic analysis raises many questions and doubts. However, the recommended reserve margins are based on the physical reliability results, so this review was limited to the physical reliability results.

4. The evaluation performed for this report was limited by insufficient information provided with regard to the details of the studies, discussed in Appendix A to this report. Accordingly, the evaluation focused on three issues having to do with how loads were represented in the RA Studies, and that were found to be inaccurate and unsupported:

a. First, the RA Studies extrapolated the relationship between cold temperatures and winter loads that occurred in some hours in recent years over much lower temperatures that have not occurred for decades in a manner that greatly exaggerates the magnitude of the loads likely to occur under extreme cold conditions.
b. Second, the “economic load forecast uncertainty” that was layered on top of the weather-related load distributions was also exaggerated, and is not supported by the underlying data it was based upon.
c. Third, the RA Studies relied upon the DEC and DEP peak load forecasts, and treated them as forecasts of mean or average peak loads; however, at least in the case of DEC, the forecast value apparently was not a mean value, and was likely several hundred MW in excess of the mean forecast, which would bias the reserve margin higher.

5. The review of these three issues leads to the conclusion that the risk of very high loads, especially in winter, was substantially exaggerated in the RA Studies, and, therefore, the recommended increases in the DEC and DEP reserve margins are unsupported and should be rejected.

6. These three issues are discussed in the next sections of this report.

III. REPRESENTING THE IMPACT OF EXTREME COLD ON WINTER LOADS

7. In recent years, very extreme cold conditions have in a few instances resulted in very high loads on the DEC and DEP systems, as further discussed in the Load Forecast Report. To accurately evaluate winter period resource adequacy, it was necessary for the RA Studies to model extreme cold and its impact on load levels.

8. 2014 and 2015 were years characterized by days colder than any that had occurred since 1996. Based on the temperature data used in the RA Study (response to SACE 2-16), 2014 and 2015 each had two days in which temperatures dropped below 10 degrees Fahrenheit; in the years before 2014, temperatures had not dropped to even 11 degrees since 1996. However, the RA Studies used 36 years of historical weather data back to 1980, and even lower temperatures were seen in some years in the 1980s and 1990s (3, 4, and 5 degrees in 1982, 1984, and 1986, respectively, and minus 5 in 1985). Therefore, to use the 36 years of weather data it was necessary to model loads under extremely cold conditions that have not been seen in over 20 years.

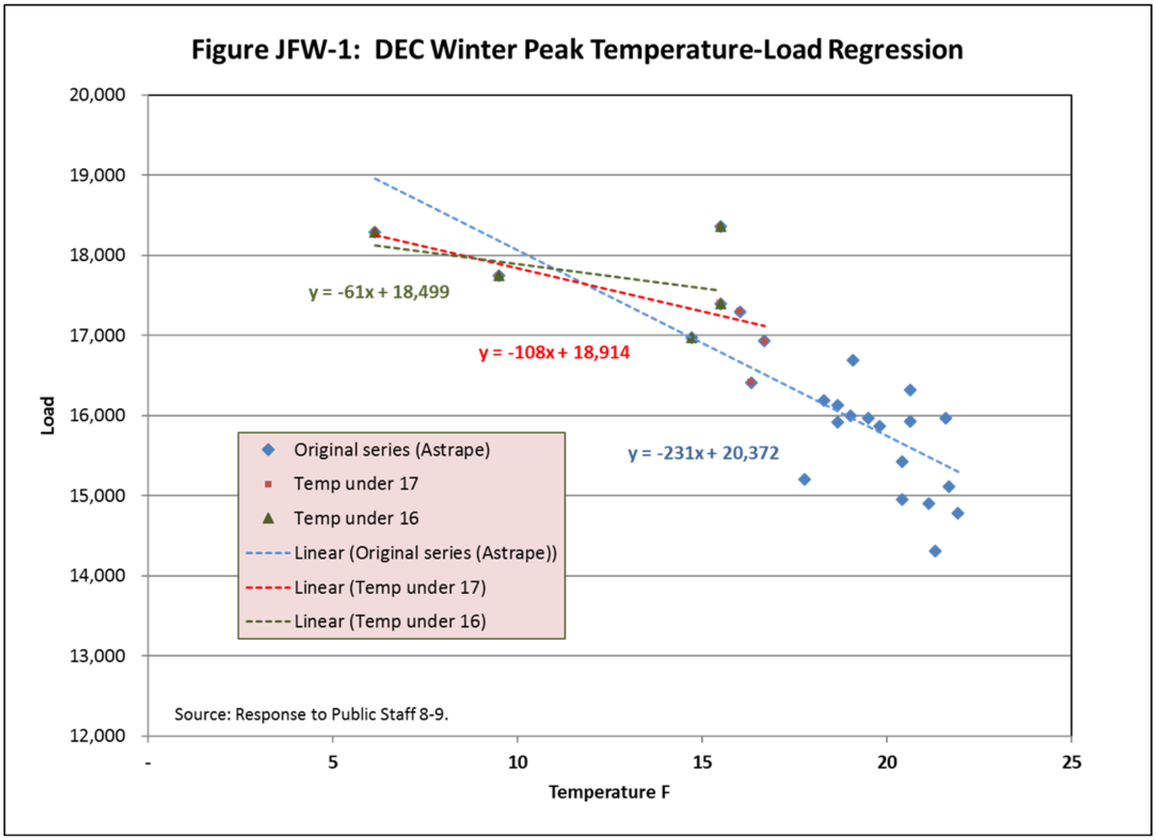
9. The most extreme recent winter loads have occurred on extremely cold mornings at about 8 AM, as shown in the Load Forecast Report. Arguably, once temperatures drop to the teens, customers may have turned on all of the equipment that will help them stay warm, and further declines in temperature may not further increase loads very much. However, the companies have not performed any analysis to determine what end uses are specifically contributing to these load spikes experienced on extremely cold winter mornings (response to SACE 2-11).

10. The RA Studies based the relationship between extreme cold temperatures and load levels on a very simple regression analysis. A more complex neural network approach was used to determine the relationship between temperature and load for most hours (DEC RA Study p. 12). However, the response to a data request (NC Public Staff 8-9) stated that "since neural networks do not do a good job of extrapolating relationships beyond conditions seen in the training data, or identifying relationships for rare conditions, we do not rely on the neural network relationships for extreme conditions." Instead, the RA Studies used regression analysis. The regression was provided in response to the same data request (Public Staff 8-9), and the equation used to represent the relationship between temperature and DEC load, under extreme cold conditions, was as follows:

DEC Load = -231 * (Temperature) + 20,372.

11. This equation means that under extreme cold conditions, for each degree the temperature falls, DEC's load is assumed to increase by 231 MW (roughly 1.3%). Four additional degrees results in 924 MW of additional load (over 5% increase).

12. This equation, and the critical 231 MW per degree assumption, were simply based on a regression (Microsoft Excel linear trend line) to fit all recent observations of DEC load and temperature 21.9 degrees and below (25 observations), as shown in the response to the data request. Figure JFW-1 shows the analysis as provided in the data request (the regression is shown in the blue dashed line and associated equation), with some reformatting and additional analysis.



13. There is no documentation of why this subset of the data was chosen, and the result is highly sensitive to the chosen range. Using observations under 20.4 degrees rather than 21.9 reduces the 231 MW value to 188 MW.

14. More important, however, the relationship between temperature and load in the more moderate temperature range is of questionable relevance to understanding the relationship for temperatures under extreme cold conditions. As suggested above, while declining temperatures lead to increasing loads, once

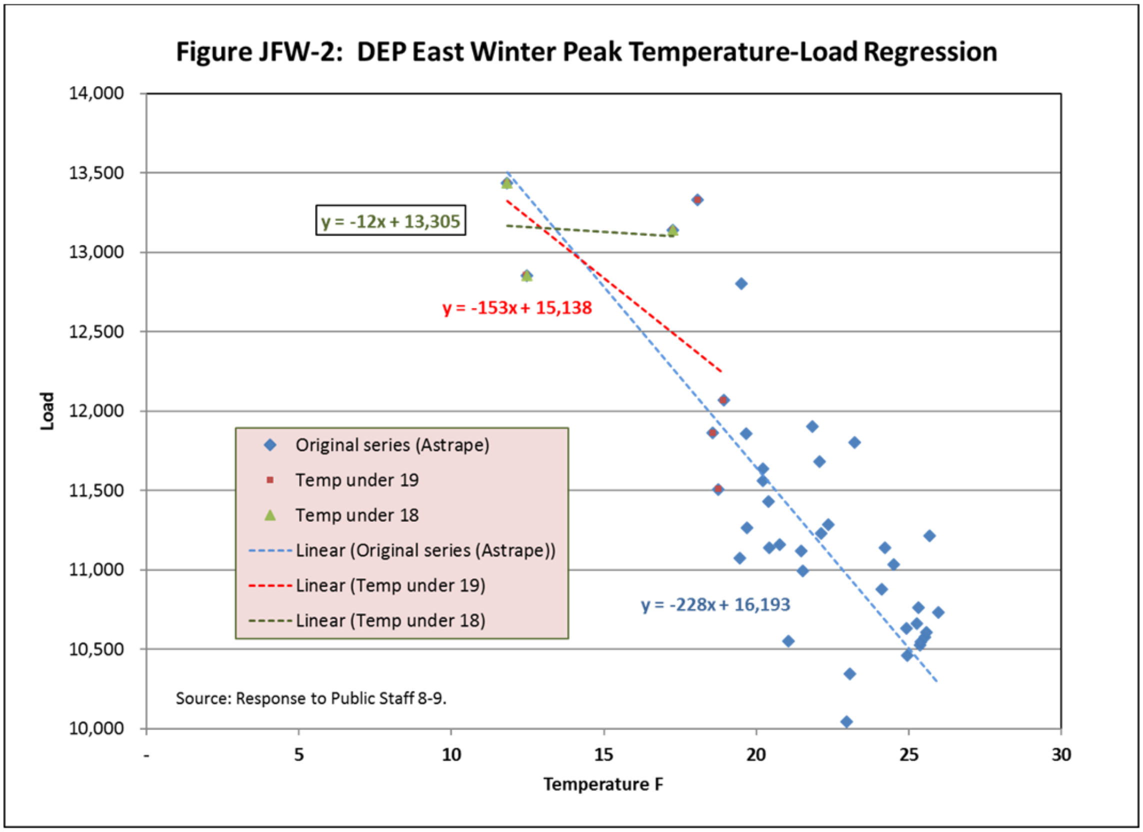
temperatures drop to very low levels a saturation effect may take place, if nearly all appliances are already deployed.

15. To better understand the relationship between extremely low temperatures and load, a regression was performed focused instead on temperatures under 17 degrees; this changed the resulting relationship between temperature and load from 231 MW per degree to 108 MW per degree, reducing the impact of further cold by over half. The result of this regression is shown by the red dashed line and equation in Figure JFW-1. Further limiting the regression to temperatures under 16 degrees resulted in just 61 MW per degree (the green dashed line and equation in Figure JFW-1), a relationship between extreme cold and load almost four times weaker than the RA Study assumed.

16. This additional analysis demonstrates two things. First, it demonstrates that the critical 231 MW per degree assumption used in the DEC RA Study was arbitrary, as it reflects the particular subset of data used in the regression. Different subsets based on different temperature ranges give very different results; the results are highly sensitive to the choice of temperature range. Second, and more important, this analysis suggests that the relationship between extreme cold and load is much weaker than 231 MW per degree; the 61 MW or 108 MW per degree estimates, more appropriately focused on the coldest observations, are likely more accurate estimates of the relationship between temperature and load under extreme cold conditions.

17. A similar analysis was conducted for DEP East, which leads to very similar results and the same conclusions. This analysis is shown in Figure JFW-2. The RA Study used 228 MW per degree (shown in blue), based on temperatures up to 26 degrees. Again, it is unclear why 26 degrees was chosen, and the relevance of observations at temperatures up to 26 degrees is doubtful. Focusing the regression on temperatures under 19 degrees results in 153 MW per degree (shown in red); and focusing the regression on temperatures under 18 degrees (shown in green; for which there were only three observations) results in only 12 MW per degree. Similarly, for the much smaller (and generally colder) DEP West zone, the RA Study based the regression on

temperatures under 22 degrees, and focusing the regression on colder observations results in a substantially weaker relationship between temperature and peak load.



18. The 231 MW per degree assumption for DEC, and 228 MW per degree assumption for DEP East, result in some very extreme peaks under the very cold conditions represented in some of the 36 weather years. Figure JFW-3 shows a graphic from the DEC RA Study illustrating how high winter peaks are assumed to go, as a result of the 231 MW per degree assumption. While the extreme cold in 2014 and 2015 resulted in extreme peak loads roughly 5% to 8% above the anticipated, normal winter peak loads in those years, the 231 MW per degree assumption results in modeling peaks in the 1982 weather year ***18%*** above the anticipated winter peak (for 2019, the year that is the focus of the RA Studies, 18% equates to over 3,300 additional MW). Modeling such extreme peaks will, of course, drive the winter reserve margin higher. Using the more realistic 61 or 108 MW per degree estimates would bring these extreme

peaks down considerably. Figure JFW-3 also shows the similar graphic from the DEP RA Study, which also reflects very extreme winter peaks (over 20% above the normal winter peaks) based on the unrealistic estimates of the relationship between extreme cold and load.

Figure JFW-3: Figure 3 from the DEC and DEP RA Studies

Figure 3. DEC Winter Peak Weather Variability

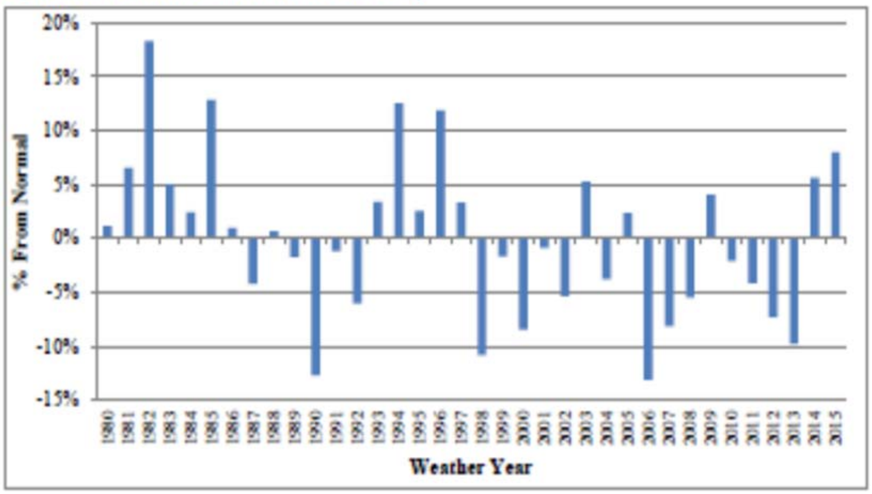
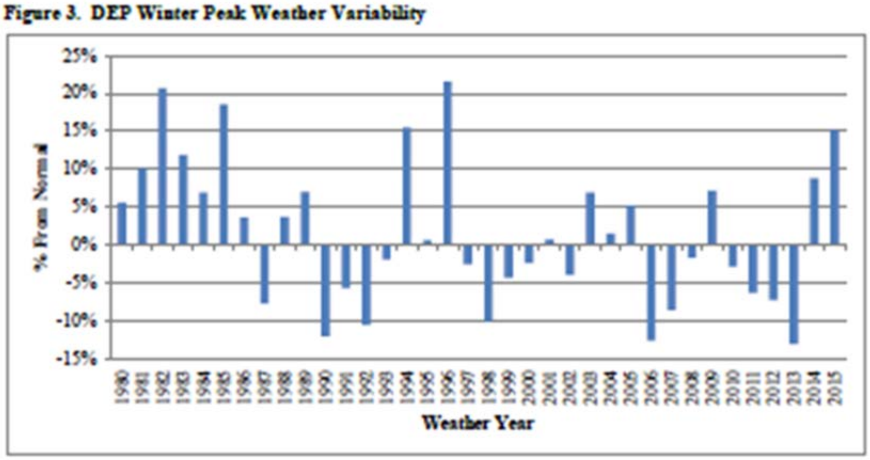


Figure 3. DEP Winter Peak Weather Variability



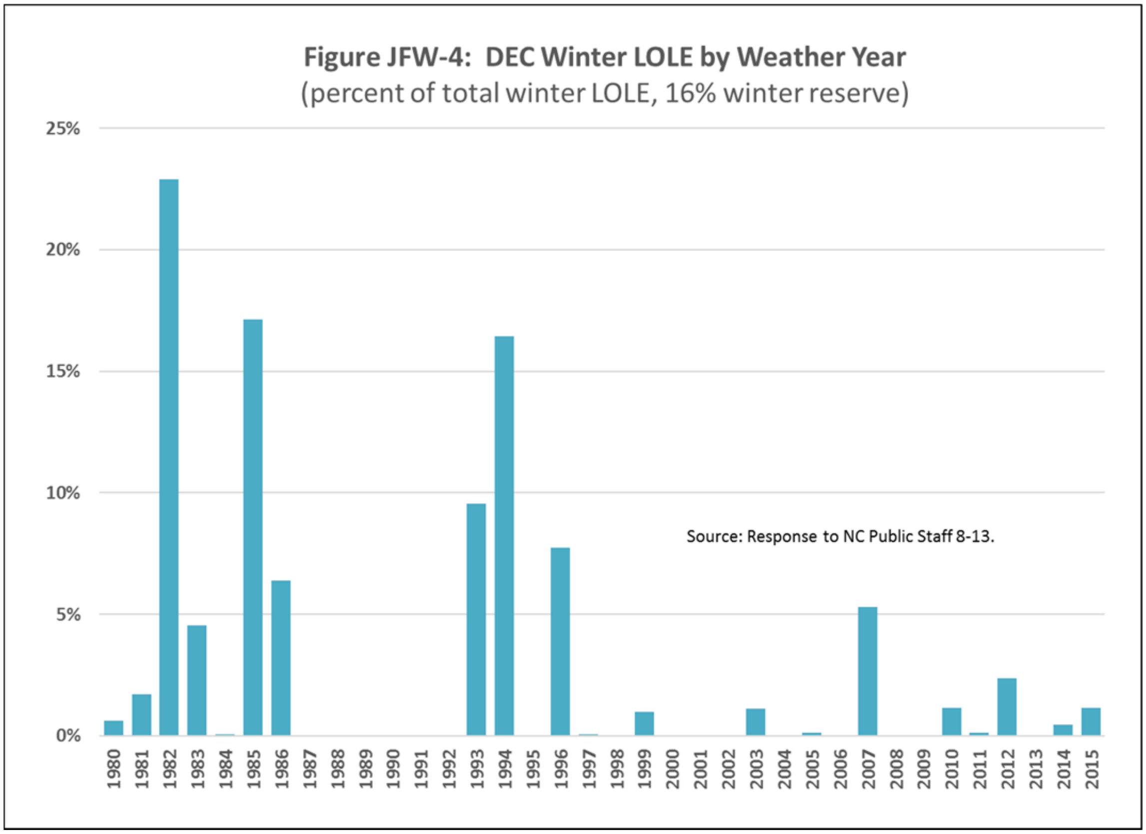
19. The critical assumptions about the impact of extreme cold on load levels were chosen based on simple regressions over rather arbitrarily-chosen temperature ranges, despite the high sensitivity of the results to the chosen ranges. This casual

approach stands in contrast to the rigorous process and analysis that the load forecasters at PJM Interconnection, LLC, who prepare peak load forecasts and evaluate reserve requirements for all or part of 13 states (including North Carolina) and the District of Columbia, underwent to enhance their load forecasting methodology following the polar vortex experience. The PJM load forecasters developed enhancements to more accurately represent the relationship between loads and extreme temperatures. The proposed changes were discussed with stakeholders over multiple meetings of the PJM Load Analysis Subcommittee before the changes were approved and implemented. PJM's enhanced methodology now employs additional "weather splines" (essentially, regressions over ranges of temperatures), in order to more accurately capture the relationships between load and temperature over different temperature ranges, including extreme hot or cold conditions.[1]

[1] See, for instance, PJM, *Item 4 – Forecast Update*, Load Analysis Subcommittee meeting September 2, 2015, slides 2-23 (describing use of four temperature ranges each for summer and for winter splines).

20. The arbitrary and inaccurate assumptions about the relationship between extreme cold and load results in modeling some very extreme winter loads in the RA Study simulations, driving the reserve margin results higher. In response to a data request (Public Staff 8-13), the winter LOLE values across the 36 simulated weather years (1980 through 2015) were provided. As noted above, 2014 and 2015 were years characterized by days colder than any that had occurred since 1996. Therefore, it should be expected that 2014 and 2015 would contribute significantly to the total winter LOLE across the 36 weather years. However, instead these two years play a small role. In the DEC RA Study, 2014 and 2015 contribute only 1.6% of the total winter LOLE across the 36 weather years (two average years out of 36 would be expected to contribute 5.6% of the total). The four years with the most exaggerated extreme loads shown in Figure JFW-3 (1982, 1985, 1994 and 1996) account for 64% of the total winter LOLE. 87% of the LOLE occurs in the 17 weather years from 1980 through 1996, while

only 13% of the LOLE occurs in the 19 years from 1997 to 2015. This data is illustrated in Figure JFW-4.[2]



21. In the DEP RA Study the results are similar. 2014 and 2015 contribute only 7.2% of the winter LOLE. The four years 1982, 1985, 1994 and 1996 account for 66% of the LOLE, and the first 17 years contribute 78%, the final 19 years only 22% of the LOLE (Figure JFW-5).

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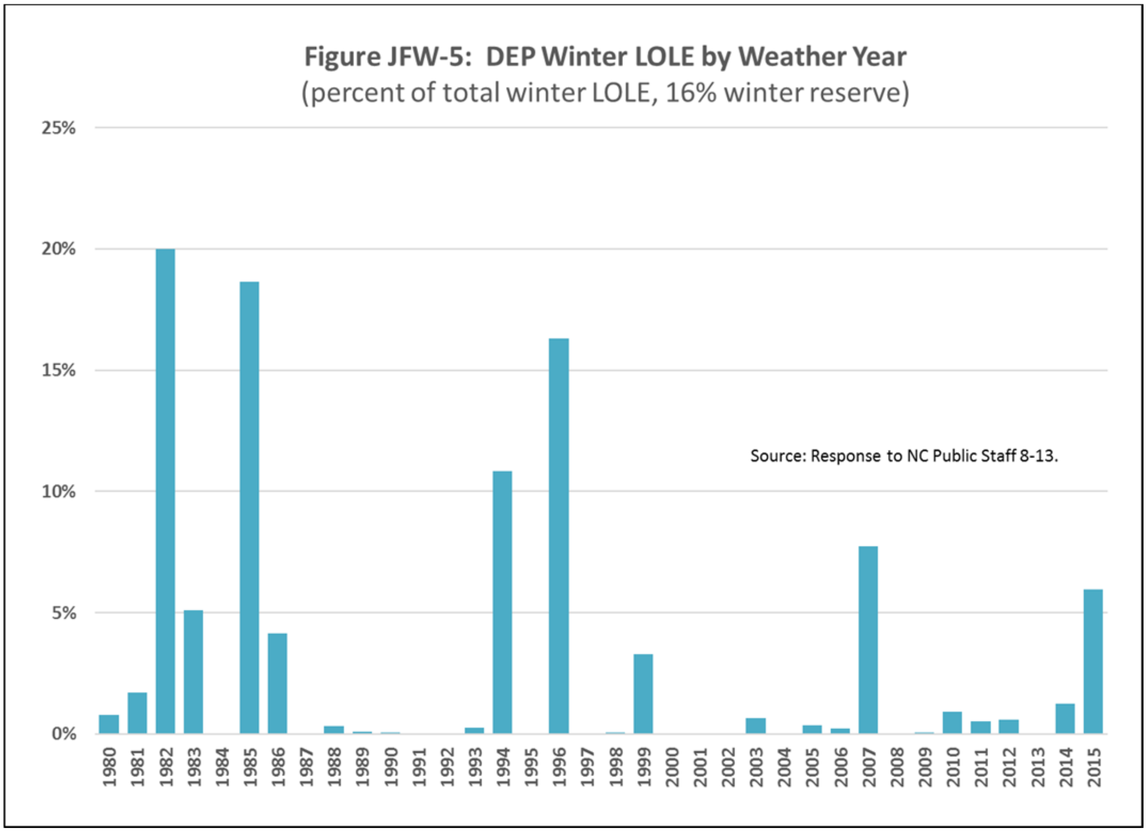
[2] The data request (Public Staff 8-13) provided results for a 16% and 18% winter reserve margin, but not the recommended 17% winter reserve margin; the above results are for the 16% winter reserve margin. Under the 18% reserve margin assumption, the contribution of 2014 and 2015 to the total LOLE is even smaller, and the role of the assumed extreme loads in the earlier years is even greater.



22. Thus, the vast majority of the winter LOLE in the RA Studies occurs in weather years long past, based on temperatures that have not been seen in decades and highly speculative assumptions about how loads would increase due to such temperatures, should they occur again. These assumptions, new in the 2016 RA Studies, drive the reserve margins higher.

IV. REPRESENTING ECONOMIC LOAD FORECAST ERROR

23. In addition to the variability of load due to weather, the RA Studies additionally include "economic load forecast error", intended to represent the possible error in four year ahead load forecasts (DEC RA Study, p. 16). The economic load forecast uncertainty is represented as a symmetric probability distribution (DEC RA Study Table 4 p. 17). A 7.9% probability is assigned to both +4% and -4% shifts in load, 24% probability is assigned to both +2% and -2% shifts, and 36.3% chance is assigned to no change due to economic load forecast error. Thus, all loads, including the extreme

weather-related load levels discussed in the prior section, are increased by an additional 4% under the highest economic load forecast error scenario, and 2% under an additional scenario assigned a 24% probability.

24. This section of the report first explains why it is not appropriate to include multi-year economic load forecast uncertainty in the RA Studies. It then explains that the probability distribution of economic load forecast error used in the RA Studies is not supported by the underlying data it was based upon, and greatly overstates the risk of sharp increases in load due to forecast error.

25. The RA Studies rationalize adding the multi-year economic load forecast uncertainty as follows: "Four years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans." (DEC RA Study, p. 16) However, this is not correct; there are many short lead time actions that can and would be taken. If load grows faster than expected, the utilities (and customers and other market participants too) would have time to adjust their plans, if the rate of load growth raised concern about resource adequacy. To name a few potential actions, the development of some new resources might be accelerated; demand response or energy efficiency programs could be increased; a planned retirement could be delayed; firm purchases from adjacent regions could be adjusted; or wholesale sales contracts could be allowed to expire. The RA Studies essentially assume the reserve margin and resource plan must be chosen three years in advance, and then remain frozen, even if load growth is much stronger than expected year after year (responses to SACE 2-22 and 2-23). This is not realistic, and assuming load can rise sharply due to multi-year forecast error, but no adjustments to the resource mix can be made over three years, biases the planning reserve margin upward.

26. It is notable that PJM, in its resource adequacy analyses, acknowledges that resource plans can and would be adjusted as needed if load grows faster than

expected. Accordingly, PJM represents only one year of economic load forecast error in its resource adequacy analyses.[3]

27. It could be appropriate to represent multiple years of forecast uncertainty in a more sophisticated model that is able to internally determine contingent actions to realistically adjust the resource mix over time as the load forecast and other resources change over time. For instance, the Electric Power Research Institute's Over/Under capacity planning model, developed by Decision Focus Incorporated in the 1970s, had this capability.[4] However, the SERVM model that was used in the RA Studies does not represent such contingent decisions (responses to SACE 2-22 and 2-23). To represent multi-year load forecast uncertainty, but not the actions that would be taken to adapt resource planning over time as such uncertainty resolves, is a flawed methodology that biases the result toward higher planning reserve margins.

28. Turning to the values used for the economic load forecast error, the DEC RA Study states (pp. 16-17) that the probability distribution was based on the historical forecasting errors reflected in the U.S. Congressional Budget Office ("CBO") U. S. Gross Domestic Product ("GDP") forecasts, and applying a 0.4 elasticity of peak demand to economic changes. The DEC and DEP load forecasts rely upon forecasts of the North Carolina economy from Moody's Analytics, so it can be questioned whether CBO U.S. GDP forecasting errors are a reasonable proxy for the applicable economic forecasting errors. Moody's forecasts over the past decade have frequently been far too high; Moody's failed to anticipate the deep recession that occurred in around 2008, and for several years after the recession was forecasting a strong recovery that never occurred.

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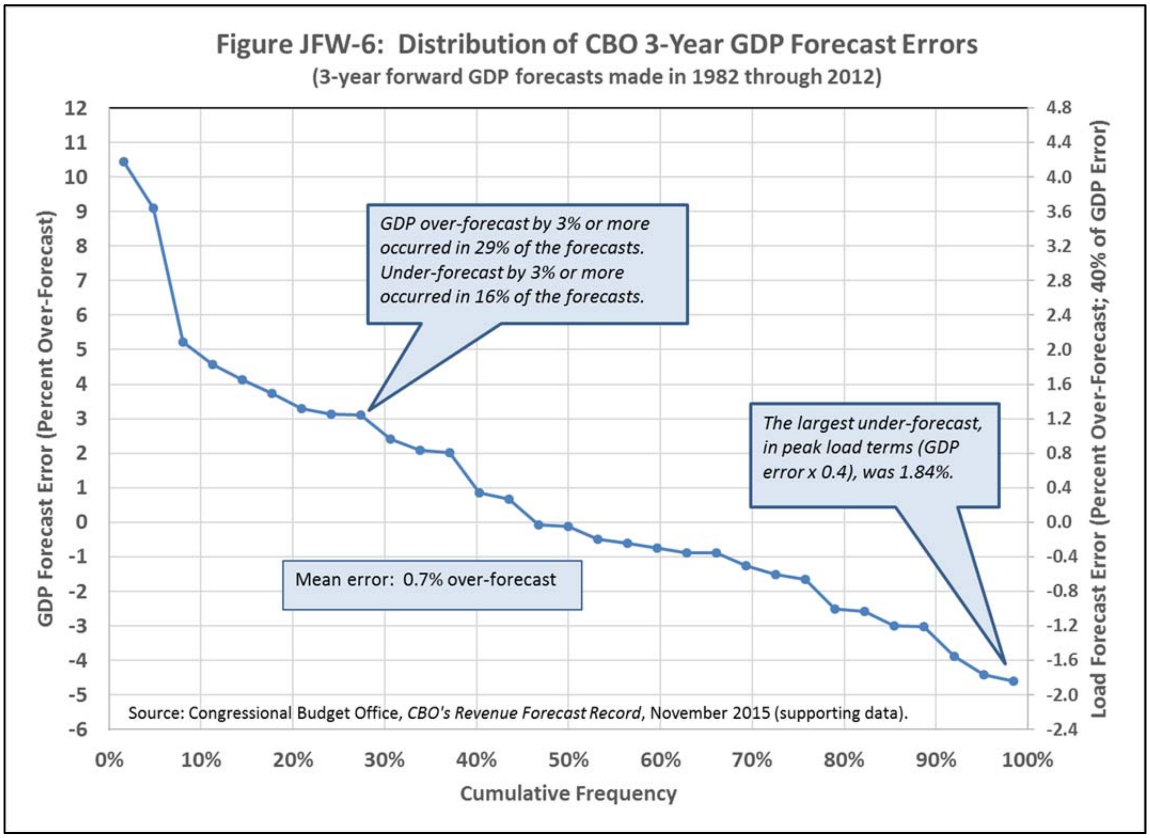
[3] See, for instance, PJM, *2012 PJM Reserve Requirements Study,* p. 20 (explaining the rationale for using a forecast error factor representing one year of forecast error).

[4] Decision Focus Incorporated, *Costs and Benefits of Over/Under Capacity in Electric Power System Planning*, EPRI EA-927, Project 1107, October 1978.

29. The CBO data is readily available, including the 3-year GDP forecast errors that were the basis for the economic load forecast error distributions used in the RA Studies.[5] Figure JFW-6 presents the full distribution of the 3-year forward GDP forecast errors. The right axis in Figure JFW-6 shows the distribution in economic load forecast error terms (GDP error x 0.4 elasticity, as noted above).



30. The distribution used in the RA Studies misrepresents the distribution of CBO forecast errors:

a. First, the CBO forecast errors, overall, are not symmetric; there is more over-forecasting than under-forecasting. The mean error was +0.7% over-forecast. A bias toward over-forecasting is reflected in the CBO's

[5] Congressional Budget Office, CBO's Revenue Forecasting Record, November 10, 2015, and Supplemental Data available at https://www.cbo.gov/sites/default/files/114th-congress-2015-2016/reports/50831-RevenueForecasting-SuppData.xlsx.

forecasts and also in those of other forecasters generally (for example, the Blue Chip Consensus of multiple forecasters, as noted in the CBO analysis of forecast errors cited above, also exhibits a bias toward over-forecasting).

b. Second, the large magnitude errors tend to be over-forecasting errors; under-forecasting errors tend to be smaller. Put another way, when economic growth is stronger than expected, the error tends to be small, but when economic growth is weaker than expected the difference can be more substantial. This is not surprising: economic downturns can be sudden, largely unexpected, and sharp, as recently seen in 2008. Surprisingly strong economic growth, by contrast, would tend to develop and accumulate more slowly over time.

31. In contrast, the economic load forecast error distribution used in the RA Studies has a mean of zero, and assigns 7.9% and 24% probability to under-forecasting peak load by 4 percent and 2 percent, respectively, as described above. However, over the thirty years of CBO data, the largest 3-year GDP under-forecast error was 4.61 percent, which translates (times 0.4) into a load forecast under-forecast of 1.84%. Thus, the RA Studies assign almost 32% probability to under-forecast errors whose magnitude (+4% or +2%, in load forecast terms) never happened even once in 30 years according to the data the distribution was purportedly based upon.

32. Consequently, even accepting the inclusion of multi-year economic forecast errors, and accepting use of the CBO data to develop the distribution, the RA Studies have misrepresented the distribution of errors, exaggerating the risk of substantial under-forecasting. This exaggeration of the potential for under-forecasting of economic load growth, in addition to the exaggeration of winter peak loads, will further bias the planning reserve margin upward.

V. RELIANCE UPON DEC AND DEP FORECASTS AS MEAN PEAK LOADS

33. The last topic of this report has to do with the interpretation of the DEC and DEP peak load forecasts as used in the RA Studies.

34. Peak load forecasts are generally intended to be median values (that have an equal chance of being too high or too low compared to the actual value, when it becomes available) or perhaps mean values (representing an average or expected value of the possible values). The RA Studies adjust the 36 load distributions such that the average of the peak loads equals the DEC or DEP forecast for 2019, essentially using the company forecasts as mean values (per the response to NC Public Staff 8-10).

35. However, in a recent supplemental response to a data request, DEC states that its peak load forecast includes 540 MW of a backstand agreement with the North Carolina Electric Membership Corporation ("NCEMC"), and that this load would not be reflected in the historical values except when the Catawba Nuclear Station was not in operation (responses and follow-up responses to data requests SACE 3-2 and 3-3). Thus, DEC has apparently added to the forecasts loads associated with a wholesale arrangement that is very unlikely to be called upon at any time. As a result, the forecasts no longer represent median or mean values. In particular, if the likelihood or frequency of the backstand agreement being called at peak times is 10%, the expected value impact of this arrangement on the peak load forecast should be 54 MW, not 540 MW.

36. For the purpose of the RA Study, any such loads should have been removed, and either treated probabilistically or replaced by the expected values. There may be other DEC or DEP wholesale arrangements that are reflected in the forecasts and also should have been adjusted to mean values for the purpose of the RA Studies. This error, which may have been due to a miscommunication or misunderstanding between Astrape Consulting and the companies, results in exaggerating the peak loads (for DEC by at least 500 MW, and perhaps also for DEP), which will lead to higher calculated reserve margins.

VI. SUMMARY AND RECOMMENDATIONS

37. This evaluation leads to the conclusion that the recommended increases in the DEC and DEP reserve margins are not supported by the RA Studies and are not necessary at this time, due to the following flaws, all of which improperly inflate the planning reserve margins:

a. The regressions used to estimate the impact of extreme cold on load levels overstate the impact; more accurate regressions more focused on colder temperatures suggest a much more moderate impact of extreme cold on load.
b. The application of multiple years of economic load forecast uncertainty is inappropriate in a model that does not represent the contingent actions that could be taken if load grows more rapidly than expected.
c. Even accepting the application of multiple years of economic load forecast uncertainty, the probability distribution used, based on CBO data, misrepresents that data, and greatly overstates the risk of sharp, unexpected increases in economic growth and load.
d. The RA Studies have assumed that the companies' load forecasts are mean values; but at least in DEC's case, wholesale commitments have been added to the forecast that are very unlikely to be called upon, so the forecast is not a mean value, and the mean value is substantially lower.

38. It is certainly appropriate to consider both summer and winter resource adequacy for planning purposes. However, because the risk and magnitude of extreme winter peak loads was greatly exaggerated in the RA Studies, the suggestions in the 2016 IRPs that planning should now be winter-focused (DEC 2016 IRP pp. 4-5; DEP 2016 IRP pp. 4-5) should be rejected. While resource adequacy was indeed challenged during the polar vortex period due to both extreme loads and very poor resource performance, the lessons learned and practices put in place since that time have addressed the resource performance risk, as noted in the RA Studies (DEC RA Study, p. 38).

39. To the extent planning reserve margins are largely a result of brief winter peaks that occur only under very rare extreme cold conditions, it will likely be more economical to develop tailored peak-shaving programs focused on such events rather than to build additional power plants to serve such rare and brief load spikes.

40. Finally, this evaluation leads to the following suggestions, for future IRPs:

a. The companies should research the drivers of sharp winter load spikes under extreme cold conditions, and study the relationship between extreme cold and load, to inform future resource adequacy studies.

b. The companies should also research the potential for load forecast errors due to economic and demographic forecast errors, and the realistic extent to which this could ultimately lead to less capacity than planned in a delivery year, also to inform future resource adequacy studies.

c. More detailed information about the RA Studies, and thorough validation, should be required. To start, all model reports, and a more comprehensive set of sensitivity analyses, should be provided.

d. The companies should consider focusing on an alternative capacity measure rather than "installed" capacity and installed reserve margin. As the rather confusing and counter-intuitive discussions in the RA Studies make clear (DEC RA Study pp. 3-4), with increasing amounts of seasonal and intermittent resources such as solar on the system, the total "installed" capacity tells little about seasonal resource adequacy, and the required installed reserve margin for each season becomes highly sensitive to the resource mix. More meaningful summer and winter reserve margin measures would compare the total seasonal *capacity value* of all resources, rather than total *installed* capacity, to the seasonal peak load forecasts. Resources' seasonal capacity values reflect the expected contributions to meeting seasonal peak loads, taking into account forced outage rates, likely availability during summer and winter peak periods (in particular, for solar), and perhaps other considerations.

APPENDIX A: LIMITATIONS OF THIS REVIEW

1. Resource adequacy studies necessarily involve numerous assumptions about loads and resources. To evaluate such a study properly requires a careful review of the various assumptions and how they interact through the simulation to create the study results. Of critical importance is the probabilistic representation of loads and resources. Because the goal is to find the reserve margin to satisfy LOLE = 0.1 (one outage event in ten years), the loss of load will occur only under extremely low-probability combinations of load and resource conditions. Therefore, to validate such a simulation (to gain confidence that the various assumptions are realistic in combination and lead to realistic results) requires careful review of, among other things, the combinations of multiple rare events that lead to the loss of load. To fully understand and valued how the loss of load occurs, the following questions should be explored:

- When loss of load occurs, what is the day of week, hour, weather condition, and load level?
- What conditions have combined to cause the extremely high load, if applicable?
- Which resources are unavailable at that time and in what quantities, and why are they unavailable? In particular, what is the state of demand response, pumped hydro, and purchases through the interties?

These are just a few of the many questions that should be explored in a detailed validation of a resource adequacy study.

2. In addition, a thorough review would consider the results of additional sensitivity analyses around various assumptions, to understand the impact of the assumptions on the results and recommendations. Sensitivity analysis will often reveal that the results are highly sensitive to certain assumptions, which may be unrealistic and suggest that further consideration of the particular values chosen for the assumptions is warranted.

3. However, such validation of the RA Studies could not be performed because the required details and sensitivity analyses were not provided in response to data requests (responses to SACE 1-9, SACE 2-18, SACE 2-26, SACE 2-27, SACE 3-4, SACE 3-18, SACE 3-19). This lack of information limited the evaluation of the RA Studies discussed in this report.

4. Furthermore, it appears that the Astrape Consulting staff who performed the analyses also did not complete such a validation exercise; responses to data requests indicate that the basic model output reports that would be used in such an effort were not even created, nor was additional sensitivity analysis performed (beyond the few documented in the reports) (responses to SACE 3-4, SACE 3-18, SACE 3-19). The apparent lack of basic validation of the simulation results raises concern about the accuracy of the RA Studies and the reliability of the resulting reserve margin recommendations.

APPENDIX B: QUALIFICATIONS OF JAMES F. WILSON

James F. Wilson is an economist and independent consultant doing business as Wilson Energy Economics, with a business address of 4800 Hampden Lane Suite 200, Bethesda, Maryland 20814. Mr. Wilson has over 30 years of consulting experience, primarily in the electric power and natural gas industries. Many of his consulting assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. Of particular relevance to this report, Mr. Wilson recently performed a peer review of a resource adequacy study prepared by Astrape Consulting using the same model used in this proceeding at the request of the Eastern Interconnection States' Planning Council (Wilson, James F., *Comments on "The Economic Ramifications of Resource Adequacy Whitepaper"*, prepared by Astrape Consulting for EISPC and NARUC, March 24, 2013). Mr. Wilson's experience and qualifications are further detailed in his CV, available at www.wilsonenec.com.