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N.C. Utilities Commission

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June 10, 2013

VIA HAND DELIVERY

Gail L. Mount
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

**RE: Duke Energy Carolinas' and Duke Energy Progress' Response to May 3, 2013 Order Requiring Verified Responses
Docket No. E-100, Sub 137**

Dear Ms. Mount:

I enclose an original and thirty-one (31) copies of Duke Energy Carolinas, LLC's and Duke Energy Progress, Inc.'s ("the Companies") Response to May 3, 2013 Order Requiring Verified Responses ("the Response"), for filing in connection with the referenced matter.

Certain information contained in the appendices to Exhibit Nos. 1 and 2 to the Response is confidential, and the Companies request that this information be treated confidentially pursuant to N.C. Gen. Stat. § 132-1.2. The redacted information contains specific unit forced outage rates, average operating hours by unit, and combustion turbine cost information. This information is proprietary, operational and cost information that would harm the Companies if disclosed publicly to competitors in the market because of its commercial value and sensitivity.

For filing purposes, I also enclose one original and one copy with the confidential information redacted. Parties to the docket may contact the Companies regarding obtaining copies pursuant to an appropriate confidentiality agreement.

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Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

Lawrence B Somers DBS

Lawrence B. Somers

Enclosures

cc: Parties of Record

CERTIFICATE OF SERVICE

I, certify that a copy of Duke Energy Carolinas, LLC's and Duke Energy Progress, Inc.'s Response to May 3, 2013 Order Requiring Verified Responses in Docket No. E-100, Sub 137, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the following parties for record:

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This is the 10th day of June, 2013.

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Request No. 1:

At the hearing for public witnesses that the Commission convened in Raleigh on February 11, 2013, it was suggested that the utilities should be required to pursue policies that were included in House Bill 135, which was introduced in the North Carolina General Assembly on February 21, 2011. That legislation includes: (a) a proposal to establish tiered electric rates; (b) a proposal to establish an energy efficiency public benefit loan fund to be used for loans to customers for energy efficiency or renewable energy projects; and (c) a proposal to create an incentive for consumers to buy EnergyStar™ qualified products. Explain your Company's position on these proposals and whether each proposal would cause the Company's IRP to result in lower electricity costs for consumers.

Response:

(a) **The Companies' concern with a tiered or inverted/inclining rate structure for all customers, such as set forth in the 2011 version of House Bill 135 and which was not enacted by the General Assembly, is that such a structure is inefficient, administratively complex, potentially confusing to customers and could lead to subsidization and customer discrimination issues. In addition, unlike the Companies' current declining block rates set by the Commission, such an inverse tiered rate structure as proposed in House Bill 135 is not cost based. The tiered electric rates described in the proposed legislation in House Bill 135 proposed to have commercial and industrial block schedules developed on a "case by case basis" which would inherently cause subsidization and discrimination concerns and raise administrative concerns with developing customized rates for all impacted customers. House Bill 135 also proposed a type of peak pricing with higher block pricing across the board, on top of the inclining energy block rates, which is quite a complex and potentially confusing mix of rate structures.**

The policy referenced in House Bill 135 attempts to insulate low income customers from higher electricity rates/bills by drawing a correlation between low income level customers and low energy use. This assumed correlation is not always true. In fact, although residential low income customers typically have smaller homes, they are more likely to be less insulated and therefore inefficient in their use of electricity with a greater penetration of electric heat (particularly in rural areas where natural gas is not as prevalent a heating source), thereby increasing their respective electricity load. Low-income customers are also more likely to use appliances like window air conditioners and electric resistant space heaters to inefficiently attempt to isolate heating and cooling to specific. In this way, inclining block rates can actually be regressive and disproportionately burdensome to low income or fixed income customers because more of their respective load would be exposed to the higher block rates.

Additionally, the proposed tiered or inverted/inclining rates in House Bill 135 would have a negative impact to industrial and large commercial loads. Industrials

and large commercial customers typically have more kWh over which to spread the Company's fixed cost (i.e., generation, transmission and distribution facilities that are required regardless of how many kWh are consumed) and that is why they pay an overall lower cost per kWh. Industrials and large commercial customers also have a higher load factor than other rate classes such as the residential class. If the industrial and commercial rates increase with consumption due to a tiered rate design, the industrials and large commercial customers may choose to not add additional production facilities, remove current production facilities or even move their business out of state reducing the need for or eliminating North Carolina jobs. Residential customers would then see their bills increase as Company facilities that were historic paid for by industrial customers are shifted to all other rate classes.

Inverted pricing is inefficient and typically isn't aligned with cost causation. In North Carolina, rates are designed to recover an embedded revenue requirement, but need to reflect marginal cost to ensure efficient use of electricity. For example, if customers benefit by saving 20¢/kWh when usage is reduced, but the utility only recognizes a cost reduction of 4¢/kWh it ultimately leads to cost shifting and higher rates for everyone.

It might be possible to design an inclining rate structure that strikes the right balance between promoting energy efficiency and keeping a sufficient revenue stream for the utility but such a design would have to carefully consider the implications and potential impacts on all customers and the utility itself. House Bill 135 did not strike that balance.

(b) It is the Companies' position that a public benefit loan fund such as proposed in the 2011 version of House Bill 135 is not the most cost-effective vehicle for promoting energy efficiency. A public benefit fund approach creates a supply of money based on an assumed level of demand; however, it does not inherently guarantee that those funds are utilized for energy efficiency programs in a manner that returns maximum value to the citizens and businesses that contribute to the fund. In contrast, North Carolina already has in place a successful model for energy efficiency programs, which is based on utility administration. This approach has been successful for two main reasons. First, commission-approved recovery mechanisms have created a financial incentive for utilities to aggressively seek out opportunities for energy efficiency investments, and to ensure those investments produce cost-effective results. Dollars are committed to such investments once the market demand is substantiated, and the Commission, consumer advocates, and other stakeholders may review expenses and results in the associated EE/DSM rider proceedings. Second, the utilities are in the best position to assess the broader system benefits of energy efficiency projects, and to tailor financial support accordingly, thereby ensuring that the broader customer base is not overpaying for those benefits. In summary, the link to market demand, the financial incentives for prudent management, and the utility's unique ability to

evaluate the system benefits of efficiency investments make utility-administered programs a much more effective vehicle for promoting energy efficiency than a predetermined pool of loan funds. Therefore, while the introduction of a public benefit loan fund to the market could produce additional energy efficiency impacts, it is questionable whether the incremental benefits to the state would justify the costs of establishing and administering such a fund.

It is the company's position that a public benefit loan fund for renewable energy projects is unnecessary because the mechanisms already exist to allow for low-cost financing of such investments. The North Carolina Renewable Energy and Energy Efficiency Portfolio Standard and rules governing qualifying facilities position electric utilities to sign purchased-power agreements with developers/owners. These contracts, combined with attractive tax incentives from both the state and federal governments, make it relatively easy to finance renewable energy projects without further loan subsidies from the citizens and businesses of the state. Therefore, the Companies' IRP analyses already indicate significant growth in renewable energy, and therefore the Companies does not believe that further subsidies such as a public benefit loan fund are not needed or justified.

(c) It is the company's position that a program targeted toward promoting the purchase of Energy Star-certified goods has the potential to produce benefits for certain products, but success would be contingent upon program design. It is important to note that Energy Star certification is approaching ubiquity in many major appliance categories, therefore incentives will not necessarily drive additional purchases. Programs that encourage customers to replace inefficient appliances with Energy Star-compliant purchases have been shown to produce efficiency gains. House Bill 135 proposed a tax on non-Energy Star products. Raising the cost of less efficient products could in some cases have the unintended effect of encouraging citizens, particularly low income customers, to keep older, even less efficient products rather than replace them with newer more efficient products. The Companies' appliance recycling programs are designed to cost-effectively remove a barrier to appliance replacement as well as ensure that the full savings of a customer's adoption of Energy Star–certified goods are realized. The forecasted impacts of that and similar future programs are already reflected in the Companies' IRP analysis. State incentives that complement the program could help to increase the system benefits, however such incremental impacts are already assumed to be included in the range of customer adoption strategies that are necessary to achieve the "High EE" case modeled in the IRP.

<u>Request No. 2</u>:

At the hearing for public witnesses that the Commission convened in Charlotte on February 28, 2013, a U.S. Department of Energy initiative was referred to as "20% by 2030."

Describe this effort, its status, the Company's position regarding the effort, and whether the effort is reflected in the Company's IRP. If it is not, please explain why this effort is not reflected in the Company's IRP.

<u>Response</u>:

The company is assuming that the U.S. Department of Energy study referenced in Request No. 2 is the one found online at:

<u>http://www.20percentwind.org/report/Chapter1_Executive_Summary_and_Overview.pdf</u>.

This study was released in 2008 and references U.S. EIA data from 2007. The Companies are unaware of any subsequent actions or legislation that has resulted from this initiative.

With respect to the DOE study in question, the study itself states that the following conclusion was reached:

> **"1.4 CONCLUSION**
>
> **There are significant costs, challenges, and impacts associated with the 20% Wind Scenario presented in this report. There are also substantial positive impacts from wind power expansion on the scale and pace described in this chapter that are not likely to be realized in a business-as-usual future. Achieving the 20% Wind Scenario would involve a major national commitment to clean, domestic energy sources with minimal emissions of GHGs and other environmental pollutants."**

In summary, and in alignment with this conclusion, the Company closely follows developments in wind generation from both a cost perspective and as a compliance option for meeting existing state and potential federal renewable energy mandates. In fact, the Company has dedicated significant resources to assist the University of North Carolina with a more detailed assessment for the potential siting of off-shore wind generation along the North Carolina coast. At this point in time, however, neither the economics of wind resources nor the legislative mandates for wind resources would suggest that the company should include in its IRPs an assumption of 20% of its energy coming from wind by 2030. Inclusion of such an assumption of significant wind generation as part of the Duke Energy portfolios would result in a more costly resource plan as demonstrated by the technology screening process contained within the filed plans.

Duke Energy Carolinas, LLC and Duke Energy Progress, Inc.'s
Response to May 3, 2013 Order Requiring Verified Responses
Docket No. E-7, Sub 137
June 10, 2013

Request No. 3:

At the public hearing that the Commission convened in Charlotte, public witness Richard Genz compared the forecasted electricity sales growth of PEC with the growth that is projected to occur in Indiana and Ohio. Mr. Genz testified that measures taken in those states had resulted in projections of reduced electric demand (Attachment B). Please address Mr. Genz's conclusions. If accurate, why can't the electric utilities in North Carolina take steps taken in Indiana and Ohio to achieve a similar result?

Response:

Duke Energy Progress, Inc. (DEP)[1] has reviewed Attachment B to the Commission's Order and provided by Mr. Genz. The growth rate for DEP represented in Exhibit 1 correctly represents the energy sales projections (less EE and demand response impacts) in the 2012 DEP IRP. However, the negative growth represented for Duke Energy Ohio and Duke Energy Indiana cannot be replicated without more information on Mr. Genz's sources. In response to this request, DEP has compared the load forecast for DEP to those of Duke Energy Ohio and Duke Energy Indiana based upon information developed internally by our load forecasting and energy efficiency departments. Utilizing the values produced internally for use in the most recently filed IRPs of each jurisdiction, the gross sales of all jurisdictions are projecting growth into the future. The growth rates do vary, though not appreciably, for the following reasons:

- **DEP, Duke Energy Carolinas, Duke Energy Ohio and Duke Energy Indiana have different local economies, population make up, retail rates environment and weather patterns. The load forecasts for each area take into account these differences and they are reflected in the forecast results.**
- **The load forecasts also include the latest estimates of how sales are expected to respond to changes in key drivers such as economic indicators, population, end-use efficiencies, weather and retail rates. Based on our analysis, customer response to these drivers varies by state.**
- **Sales for some territories are expected to recover sooner while others are expected to recover later or more gradually, because each service area is in a slightly different stage in the economic cycle/recovery as evidenced by trends in unemployment, income and spending.**
- **The forecast impacts on load growth associated with incorporating utility sponsored EE programs or complying with a state commission's mandate, vary by jurisdiction and the load forecasts show that include those impacts.**

In addition to the differences in load forecast, EE mandates also vary by jurisdiction. It is important to note that while EE mandates may be more stringent in Ohio and Indiana

[1] Progress Energy Carolinas, Inc. (PEC) changed its name to Duke Energy Progress, Inc. on April 29, 2013.

than in the Carolinas, the mandates still do not guarantee that these levels of EE are achievable in a cost-effective manner over time. DEP remains confident in the load forecast and energy efficiency projections developed within the Company and believes that the projected sales and EE accurately represent the expectations in each jurisdiction.

Request No. 4:

In its renewable energy and energy efficiency portfolio standard (REPS) compliance submittal dated March 13, 2013, in Docket No. E-7, Sub 1034, DEC filed a "Summary of Photovoltaic Generation Interconnection Study Report," as Byrd Exhibit No. 4. What are the implications of this study's findings for future solar-powered electric generation in North Carolina?

Response:

The study's findings highlight the opportunities and challenges associated with solar generation. The study focused primarily on the distribution system impacts associated with localized high penetration of solar highlighting both challenges and opportunities. The study noted the potential for facility upgrades or accelerated replacements on circuits with high penetrations of solar installations. While the study in and of itself does not present immediate implications for solar generation in North Carolina, it does highlight potential issues that warrant further consideration as the number of solar installations in the State continue to grow.

In 2012 both DEC and DEP included a certain level of renewable solar generation in their IRPs, but, in reality, the size, total amount, locations, and impacts on the system are still largely unknown. At the time of the preparation of the 2012 IRPs, the interest in solar as reflected in the transmission interconnection queue was small. Over the last 6 months, that situation has changed substantially. As of April 2013, there were over 1900 MWs of announced potential solar generation projects greater than 1 MW in DEC and DEP retail service areas. North Carolina has become particularly attractive for solar development due to a combined state and federal tax credit that reduces the installed cost of solar by as much as 65%. This level of subsidization paired with solar development cycles of less than one year could result in dramatic changes in penetration levels of solar resources in a short period of time. However, until the solar generation is actually installed and operating, the Companies are hesitant to include specific projects in their respective resource plans. Historically, it has been difficult to predict how much of the expressed interest in projects actually comes to fruition.

The Companies are currently initiating a comprehensive study seeking to identify and, where possible, quantify potential benefits and costs of solar generation across the entire generation, transmission and distribution systems. The goal of such an effort would be to fully understand the physical implications of large levels of solar penetration on the NC electric grid. In addition to the physical system impacts, the associated financial benefits and costs will be quantified in order to ascribe the appropriate economic impacts to this resource. These study results would then be incorporated into the resource planning and

avoided cost processes in order to reach the optimal economic solution when building or procuring solar resources.

Given the potential magnitude of solar in North Carolina, Duke Energy Carolinas is concerned about the potential cross-subsidization of solar generation causes. It will be critical to "get the rules right" quickly to ensure retail customers without solar generation are not unduly subsidizing solar providers or other retail customers with solar generation. This will likely involve addressing issues associated with intermittent distributed generation such as net metering, avoided cost methodology, transmission and distribution impacts, as well as associated system operations implications. Issues such as backstanding, voltage support and distribution O&M impacts will all need to be addressed.

If these issues are addressed properly and quickly, it will result in appropriate price signals for all customers and solar providers, whether utility-built or purchased from the market. This will ensure all customers are protected from cross-subsidization and that the appropriate amount of solar generation is brought onto the system without unintended consequences.

Request No. 5:

Numerous citizens at the hearings for public witnesses commented that DEC's Riverbend Steam Station on Mountain Island Lake near Charlotte "is the oldest, dirtiest coal-fired power plant in the region, emitting toxic mercury and other chemicals into the air, as well as cancer-causing arsenic and other toxins directly into Mountain Island Lake, drinking water for 860,000 Charlotte residents. Riverbend's two massive coal ash waste containment dams are leaking dangerous poisons into our drinking water, threatening our health, our water, our lake and our property values." How has DEC addressed these concerns? What are DEC's plans for addressing them further in the future?

Response:

DEC does not agree with the public witness comments asserted in Request No. 5. DEC has been monitoring water quality in Mountain Island Lake since 1953. The lake's water quality remains good, fish are healthy and drinking water supplies are safe. During its entire period of operation, Riverbend Steam Station has been in compliance with both state and federal air and water quality regulations that are included in the permits issued to the plant. Water quality permits issued by the State assure that all uses of the water in Mountain Island Lake are protected including the use of the water as a supply for Charlotte Mecklenburg Utility Department (CMUD). The water that CMUD withdraws from Mountain Island Lake and treats to distribute to the citizens of Mecklenburg County meets the Safe Drinking Water Act standards established by EPA. Furthermore, there have been no levels of toxic chemicals emitted from the plant that have exceeded National Ambient Air Quality Standards set by EPA or the health-based air toxic standards established by the state of North Carolina.

The volume of ash basin seepage at Riverbend is extremely small and has zero impact to

the overall water quality in the lake. Seepage is necessary for an earthen dam's structural integrity. DEC regularly samples groundwater at Riverbend's ash basins and reports the data to the State. Groundwater sampling at Riverbend's ash basins finds elevated levels of iron and manganese only, both of which are common to North Carolina soils and pose no health risk to drinking water.

As part of DEC's modernization efforts, Riverbend retired on April 1, 2013. DEC plans to close its ash basins once they are no longer needed in close coordination with state regulators. DEC is evaluating multiple closure options to ensure the Company selects a method that provides long-term water quality protection.

<u>Request No. 6</u>:

An energy efficiency study conducted by Georgia Tech (in cooperation with Oak Ridge National Laboratory) shows that there is significant potential for additional energy efficiency in North Carolina. Does your company agree with the findings of this study? If not, please explain why not? Explain whether and how such findings, if valid, are factored into your Company's IRP.

<u>Response</u>:

The Georgia Tech study referenced in Request No. 6 projects electric energy efficiency potential of 10.95 million MWhs across the entire state of North Carolina by 2020 (not just the DEC and DEP service territories in North Carolina), and 19.76 million MWhs by 2035. Although difficult to ascertain in the report, the explanation of the derivation of these figures suggests that the potential savings were estimated based on the market characteristics of the South Atlantic region as a whole, and then scaled to each state based on customer class load. It does not appear that utility-by-utility load analysis was performed.

DEC and DEP assert that more accurate estimates can be derived through market-specific analysis, rather than through regional projections that have been scaled to approximate energy efficiency potential in North Carolina. Therefore, in 2012 DEC and DEP commissioned third-party studies of energy efficiency potential based on specific assessments of load, customer mix, building stock and industrial sectors in our territories. The authors of those studies then performed assessments of specific energy efficiency technologies based on the DEC and DEP market characteristics. The results of the independent studies indicated economic potential of 11.9 million MWhs in the DEC NC territory by 2031, and 9.1 million MWhs in the two-state DEP territory by 2027 (the two independent companies modeled different analysis horizons pre-merger). These figures were then discounted in each company's 2012 IRP base case to reflect the fact that consumers in all sectors often forego investments in energy efficiency measures due to competing demands for their limited financial resources.

It is the Companies' assessment that the conclusions of the DEC- and DEP-commissioned studies and the Georgia Tech study are not in conflict, and that the apparent discrepancies

between reports, adjusting for the inclusion of South Carolina in the DEP potential, can be explained as follows:

- **Varying time horizons: The Georgia Tech study forecasted potential in 2035, while the DEC and DEP studies extended only to 2031 and 2027, respectively. Obviously, additional energy efficiency gains would be expected when a longer time horizon is considered.**
- **Varying cost thresholds for economic potential: The Georgia Tech study included programs that were assumed to be economically feasible from a customer perspective up to an industrial rate of 6 cents/kWh, a commercial rate of 9.0 cents/kWh and a residential rate of 10.6 cents/kWh. The DEC and DEP studies used an assumed system avoided cost from a utility planning perspective of 7 cents/kWh to assess economic potential.**
- **Differing treatment of efficiency gains from codes and standards changes: The DEC and DEP energy efficiency forecasts reflect only measures that can be targets for incentives or otherwise promoted under utility programs. Efficiency improvements achieved through building codes, appliance standards, and the natural replacement of end-of-life equipment are largely captured in the load forecast in the IRPs rather than in the energy efficiency forecast. In contrast, the Georgia Tech study counts these sources in its assessment of energy efficiency potential.**

It is the Companies' belief that, in light of the methodological discrepancies above, the Georgia Tech report does not represent a significant departure from the economic potential analysis upon which the DEC and DEP energy efficiency forecast were based, and that any underlying differences in the assessments would be overshadowed by the uncertainty associated with customer adoption rates. Furthermore, DEC's modeling of both "Base" and "High EE" cases in its IRP is intended to illustrate the impact of this range of uncertainty.

<u>Request No. 7</u>:

In 2006, GDS Associates, Inc. prepared a report entitled "A Study of the Feasibility of Energy Efficiency as an Eligible Resource as Part of a Renewable Portfolio Standard for the State of North Carolina.[3] That report stated that "capturing the achievable cost-effective potential for energy efficiency in North Carolina would reduce electric energy use by 14 percent by 2017." Does your Company agree with this conclusion? If not, why not? Will North Carolina achieve those results? If not, why not?

<u>Response</u>:

The GDS report referenced in Request No. 7 was completed in 2006. At that time it estimated the "achievable cost-effective potential" for energy efficiency in North Carolina to be 14% by 2017. The report defined "achievable cost-effective potential" as:

> ***"...the potential for the realistic penetration of energy efficient measures that are cost-effective according to a calculation of the levelized cost per lifetime kWh saved, and would be adopted given aggressive funding levels, and by determining the level of market penetration that can be achieved with a concerted, sustained campaign involving highly aggressive programs and market interventions. As demonstrated later in this report, the State of North Carolina would need to continue to undertake an aggressive effort to achieve this level of electricity savings. (page 7)."***

As GDS acknowledges in the excerpt above, an aggressive effort would be required to achieve the high levels of market penetration assumed in its study. For example, GDS assumed an average penetration rate of 80% for measures targeting high efficiency equipment and building practices in the residential, commercial and industrial sectors (page 29). While the Companies aspire to attain such aggressive penetration rates through their programs, based on experience to date, DEC and DEP believe it is unrealistic to assume that a portfolio of programs that rely on independent customer investment choices will achieve such high levels. Additionally, it is important to note that the GDS study was completed in 2006, the year prior to the passage of North Carolina Senate Bill 3, which granted large industrial and commercial customers the ability to "opt-out" of their utilities' DSM rider. Therefore it cannot be assumed that utility programs will be able to capture the full potential of commercial and industrial energy efficiency, although some portion of "opted-out" customers may invest on their own, with those self-directed impacts showing up in the utility's load forecast rather than the EE program forecast.

Request No. 8:

In March of 2010, the American Council for an Energy Efficient Economy published a report entitled "North Carolina's Energy Future: Electricity, Transportation, and Water Efficiency."[4] The report concluded that, "while the state has already taken some steps toward its clean energy future and has a strong and growing base of clean energy businesses, our analysis finds that significant potential for energy efficiency as a resource will remain untapped over the next 15 years if the state continues on a business-as-usual track." Does your Company agree with this report's findings? Why or why not?

Response:

The ACEEE report referenced in Request No. 8 asserts that energy efficiency potential would remain largely untapped in North Carolina under a "business as usual" scenario. The Companies would not have disagreed with the accuracy of that statement at the time it was issued—March of 2010. At that time, North Carolina was approaching an important energy efficiency inflection point; both DEC and DEP were still in the early stages of ramping up aggressive energy efficiency programs based on the then-recent approvals of new energy efficiency portfolios and cost recovery mechanisms. Since program inception, both utilities have delivered significant energy efficiency savings to their customers in the state—DEC's save-a-watt portfolio has produced 1.56 billion kWhs and almost 2,000 MW of DSM related savings, while DEP has delivered 560 million kWhs and 355 MW (including DSDR) of savings.

The Companies' progress in reducing customer load through energy efficiency is the direct result of state policies and associated regulatory mechanisms that encourage utilities to pursue all cost-effective energy efficiency. Through these efforts, the Companies have learned that a wide range of customer engagement strategies are required to promote energy efficiency measures, that those strategies can create significant variability in the cost effectiveness of programs targeting different customer groups, and that many customers cannot be cost-effectively moved to measure adoption at all. So while the company agrees that there remains significant potential for further energy efficiency gains in North Carolina, we believe that the ACEEE assessment significantly overstates realistic expectations for customer adoption.

Furthermore, it is important to note that of the 24% efficiency potential estimated by ACEEE for the 2025 time horizon, 4.8% is attributed to increases in building codes and appliance standards, which are to a significant extent captured in the Companies' load forecasts.

It is also important to note that the ACEEE report attributes the largest potential savings—12.9% in the median case—to a more stringent energy efficiency resource standard (EERS). However, the adoption of a higher EERS does not, by itself, guarantee greater energy efficiency achievement if utilities or other program administrators are expected to continue to deliver cost-effective programs. Instead, the company asserts (and our aggressive work to develop and deliver new programs illustrates) that the current utility cost recovery and incentive mechanisms encourage us to maximize cost-effective energy efficiency; therefore, imposing a high EERS should not be expected to increase results unless the higher standard is accompanied by a relaxation of least-cost planning guidelines. Said another way, utilities and state entities can increase financial inducements to customers to try to meet a higher EERS, but those inducements will likely exceed the cost of traditional supply options long before the technical energy efficiency potential is reached.

On another note, in its study, ACEEE describes the method it used to estimate energy efficiency potential on page 12:

"We conducted a meta-analysis to review and summarize key information from several energy efficiency market potential studies that have already been conducted in North Carolina, the greater Southeast region, and the nation as a whole. This meta analysis supplants the sector-specific economic potential analyses we have conducted in our previous reports in other states."

On Page 92, the authors elaborate on the details of the "meta analysis":

"The meta analysis of the energy efficiency market potential studies for North Carolina includes three studies conducted between 2003 and 2008. For this review we focused on the achievable and cost-effective potential of energy efficiency measures. When this type of scenario was not specifically included in the study, we evaluated the scenario that most closely resembled the methodology and savings potential of a cost-effective, achievable scenario."

ACEEE's methodology appears to rely primarily on its analysis of three other studies, ranging from 5-10 years old, as well as a couple of regional and national level studies that did not include North Carolina-specific assessments. Furthermore, ACEEE acknowledges that this is a different, and arguably less rigorous, approach than ACEEE has taken in other states. As a result, the Companies question the current relevance of the report because it is based on conclusions drawn from other organizations' potentially outdated analyses, the application of which, ACEEE concedes, may have been somewhat different than the original authors intended.

Request No. 9:

Explain and demonstrate whether and how your Company's IRP projects full compliance with REPS.

Response:

DEP and DEC are fully committed to compliance with NCREPS requirements through a combination of energy efficiency (EE), out-of-state renewable energy credit (REC) purchases, thermal REC purchases, contracted in-state and out-of-state renewable energy resources, and potential ownership of renewable energy resources. However, the Companies reflect that compliance differently in the 2012 DEC and DEP IRPs.

The bullets below include the important assumptions for NCREPS compliance in the 2012 IRPs:

- **DEC's IRP included a compliance plan that demonstrated compliance throughout the planning horizon. This plan utilized currently contracted resources, EE, purchased RECs and a projection of future undesignated renewable resources to meet full NCREPS requirements. The DEC 2012 IRP included plans regarding renewable energy resources based primarily on the presence of existing renewable energy requirements, as well as a projection of additional undesignated renewable resources. DEC also assumed a renewable energy standard in SC beginning in 2016.**

- **PEC noted in its 2012 IRP that future compliance will be met with a cost-effective mix of renewable resources, EE, thermal RECs, and out-of-state RECs. PEC only included signed renewable resources for the purpose of capacity and energy contributions to the 2012 IRP. PEC chose not to include undesignated capacity beyond currently contracted resources, but remains fully committed to meeting the renewable energy compliance requirements as outlined in NCREPS.**

- **Despite the differences in the IRP planning assumptions, both PEC and DEC continually evaluate the renewables market in an effort to meet their overall NCREPS requirements in the most cost-effective manner possible.**

- **The intention for PEC and DEC in the 2013 IRP is to incorporate an NCREPS-compliant forecast of a mix of renewable resources, both designated and undesignated. These resources will include renewable resources, EE, thermal RECs, and out-of-state RECs.**

Specific details of the PEC NCREPS compliance plan utilized in the IRP may be found in Appendix D of the 2012 IRP on pages D-1 through D-12. Details of the DEC NCREPS compliance plan utilized in the IRP may be found in Chapter 5 of the 2012 IRP on pages 59 through 63.

Request No. 10:

What is the projected population growth for North Carolina that is embedded in the Companies' electric sales forecasts? Specifically, what is your Company's projection for total State population for the year 2027?

Response:

The North Carolina Office of State Budget and Management is the source of the population projections used in the Spring 2012 Forecast. Their link is below.

http://www.osbm.state.nc.us/ncosbm/facts_and_figures/socioeconomic_data/population_estimates.shtm

The North Carolina population for 2027 used in the Spring 2012 Forecast is 12,066,113.

Request No. 11:

In DEC's IRP, on p. 21, DEC shows an average annual retail sales load growth of 0.5% from 1996 to 2011. However, DEC's 2012 IRP is based on a projected average annual retail sales load growth of 1.4% from 2011 to 2031. What facts and analysis did DEC use in arriving at the projected average annual retail load growth of 1.4% from 2011 to 2031? How did DEC factor in its experience of an annual retail sales load growth of only 0.5% from 1996 to 2011 into DEC's projection of an average annual retail sales load growth of 1.4% from 2011 to 2031?

Response:

It must be noted that the most severe economic downturn since the Great Depression occurred in 2008-2009. As a result, DEC retail sales declined 2.0% in 2008 and nearly 5.0% in 2009. Plus, the economic recovery since then has been very sluggish. Thus, any growth rate calculation involving recent years will appear low.

In addition, the textile industry in North Carolina has significantly declined in the past 15 years. In 1998 DEC's sales to the textile industry totaled nearly 12,000 Gwh. In 2012 the

figure was 3,900 Gwh.

To arrive at a growth rate of 1.4% from 2011 to 2031, DEC developed long-term econometric models by class, that relate kwh sales to factors such as weather, price of electricity, and various economic variables such as Real Income, Real GDP and Exchange Rates, as well as Service Area Population Projections.

DEC's economic consultant, Moody's Analytics, projects a strong rebound in the economy beginning in 2015, and projects long-term GDP growth in the Carolinas of nearly 3.2% with no recessions. Also, the state governments of North Carolina and South Carolina project the population in the DEC Service Area to grow at 1.0% annually. Further, in the future, small, steady declines are expected in the textile industry rather than the massive reductions seen in the past.

The coefficients from the long-term econometric models are then applied to the projections of the economic and population variables to arrive at the energy forecast.

Perhaps a more accurate view of DEC's historical growth is the period 1997-2007, before the onset of the extreme downturn. On a weather adjusted basis, the growth of DEC Retail Sales excluding Textiles was 2.2% from 1997-2007. The economic conditions in this period most closely align with the economic assumptions embedded in the 2012 Forecast. Thus, compared to the growth rate in that period, DEC believes that its 1.4% forecasted load growth is reasonable for its planning purposes.

Request No. 12:

In the Charlotte Business Journal of November 29, 2012 (Attachment C), President Jim Rogers is quoted as saying the company's load growth will be lower than projections in the economic models. Please explain.

Response:

The referenced Charlotte Business Journal article states in pertinent part,

"Duke Energy Chief Executive Jim Rogers expects demand for electricity may grow even more slowly than the anemic 1% per year predicted by most experts – and by Duke itself in the most recent long-range plan. 'The great thing about being CEO is you don't have to agree with the experts. ... I think demand for electricity may be flat or declining in the future because of these productivity gains in the use of electricity.'"

In the quote from the article above, Mr. Rogers does not specify whether he is speaking about the national demand, the demand of Duke Energy's six regulated utilities, or a specific utility. He also does not specify in this quote whether he is speaking of overall electricity demand or a specific class such as residential demand. He is expressing a personal opinion. The load forecasts included in the 2012 IRPs filed by DEC and DEP were prepared in the Spring of 2012. These load forecasts included Carolinas' specific economic conditions and

population growth statistics that differ from other parts of the country. The load forecasts were reviewed with DEC and DEP senior management prior to inclusion in the IRPs. The Company stands by the forecast included in its 2012 IRPs as an accurate forecast for the purposes of preparing the 2012 IRPs. These forecasts are updated annually and new forecasts will be reflected in the 2013 DEC and DEP IRPs.

Request No. 13:

On p. 86 of its IRP, DEC states that its 2012 IRP is based on a reserve margin of 15.5%. During each of the years 2001 through 2011, on what date and in what amount was the highest portion of DEC's reserve margin utilized to serve DEC's system retail requirements? Or, stated another way, during those years what was the lowest actual reserve margin that DEC ever experienced, and when did this occur?

Response:

DEC has calculated actual reserve margin calculations beginning in 2006. Calculations have not been performed and are not readily available prior to 2006. However, for the period 2006 through 2011, the lowest actual reserve margin was 2.2% and occurred on August 9, 2007 in hour 17. This actual reserve margin represents the operating reserve margin without impacts of DSM. The planning reserve margin is developed to account for abnormalities in weather, unit availability and load forecast error, whereas actual reserve margin reflects the actual impacts of these events. Accordingly, the actual reserve margin is expected to be substantially lower than the target planning reserve margin at times. DEC utilized a target planning reserve margin of 15.5% in its 2012 IRP.

Request No. 14:

Has DEC conducted an analysis or study of the potential for using neighboring wholesale resources, such as generation owned by TVA or generation located in PJM, to supply DEC's reserve margin or some portion of DEC's reserve margin? If so, please provide a copy of that study or analysis. If not, please explain why DEC has not conducted such an analysis or study.

Response:

Yes, the "Duke Energy Carolinas 2012 Generation Reserve Margin Study" prepared by Astrape Consulting for DEC's 2012 IRP (attached hereto as Exhibit 1) included the benefit of being interconnected to neighboring utilities such as TVA, Southern, PJM and SCANA. The reserve margin requirements for DEC would have been substantially higher in this study had these utilities' resources not been taken into account. Furthermore, the goal of the IRP process is to meet customer needs for a reliable supply of electricity at the lowest reasonable cost. The plan that has been identified as the preferred plan then serves as a benchmark against which purchased power opportunities are measured. Before proceeding with a self-build option, it must be determined whether there are any purchased power alternatives available that would maintain the system reliability level in

a more cost-effective manner. Depending on the circumstances, DEC generally solicits the wholesale market before making resource decisions. Such an evaluation could include a formal or informal RFP to evaluate the feasibility of purchasing equivalent generation resources from the wholesale market. DEC evaluates the cost, reliability, flexibility, environmental impacts, risk factors, and various operational considerations in determining the optimal resource addition for a given situation. DEC will continue to evaluate the wholesale market and will utilize purchased power options when they are cost-effective options to reliably meet its customers' needs. The discussion of multi-area modeling begins on page 32 of the attached Exhibit 1.

Request No. 15:

In PEC's IRP, on p. 8, PEC shows a retail sales reduction of 0.5% from 2002 to 2003, a retail sales reduction of 4.1% from 2010 to 2011, and an overall growth in retail sales of 3.3% from 2002 to 2011. However, as stated on p. 6, PEC's 2012 IRP is based on a projected average annual retail sales load growth of 1.2% from 2012 to 2027. What facts and analysis did PEC use in arriving at the projected average annual retail load growth of 1.2% from 2012 to 2027? How did PEC factor in its experience of an overall retail sales load growth of only 3.3% from 2002 to 2011 into PEC's projection of an annual retail sales load growth of 1.2% from 2012 to 2027?

Response:

The response to this question for DEP is similar to the response in Request No. 11 for DEC. The severe recession in 2008-2009 and the large structural decline in textiles make any growth rate that ends in 2011 appear to be artificially low.

In general, the load forecast contained in the 2012 DEP IRP is based on 20-25 years of historical data, and uses drivers such as real income, real GDP, population, real prices, and weather variables. It is the long-term responsiveness of electric sales to these variables, as well as the projection of these variables, that determine the forecast. To arrive at a growth rate of 1.2% from 2012 to 2027, DEP developed long-term econometric models by class, that relate kwh sales to factors such as Weather, Price of Electricity, Real Income, as well as Service Area Population Projections.

DEP's economic consultant, Moody's Analytics, projected a strong surge in real income of 4.3% in 2014 and 3.4% in 2015, and projected long-term Real Income growth in the Carolinas of 2.7%, with no recessions. Also, the state governments of North Carolina and South Carolina project the population in the DEP Service Area to grow at 1.1% annually. Further, in the future, small declines are expected in the textile industry rather than the large reductions seen in the past.

The coefficients from the long-term econometric models are then applied to the projections of the weather, economic and population variables to arrive at the energy forecast.
Similar to DEC, a more accurate view of DEP's historical growth is the period 1997-2007, before the onset of the extreme downturn. On a weather adjusted basis, the growth of DEP Retail Sales excluding Textiles was 2.1% from 1997-2007. The economic conditions in this

period more closely align with the economic assumptions embedded in the 2012 Forecast. Given the expected Real Income growth of 2.7% and Population growth of 1.1%, DEP believes that its 1.2% forecasted load growth is reasonable for planning purposes.

Request No. 16:

On p. 22 of its IRP, PEC states that its 2012 IRP is based on a reserve margin of 15% to 18%. During each of the years 2001 through 2011, on what date and in what amount was the highest portion of PEC's reserve margin utilized to serve PEC's system retail requirements? Or, stated another way, what was the lowest actual reserve margin that PEC experienced during those years, and on what date did it occur?

Response:

DEP has calculated actual reserve margin calculations beginning in 2006. Calculations have not been performed and are not readily available prior to 2006. However, for the period 2006 through 2011, the lowest actual reserve margin was 7.1% and occurred on August 6, 2008. This actual reserve margin represents the operating reserve margin without impacts of DSM and curtailment riders. The planning reserve margin is developed to account for abnormalities in weather, unit availability and load forecast error, whereas actual reserve margin reflects the actual impacts of these events. Accordingly, the actual reserve margin is expected to be substantially lower than the target planning reserve margin at times. DEP utilized a target planning reserve margin of 14.5% in its 2012 IRP.

Request No. 17:

Has PEC conducted an analysis or study of the potential for using neighboring wholesale resources, such as generation owned by TVA or generation located in PJM, to supply PEC's reserve margin or some portion of PEC's reserve margin? If so, please provide a copy of that study or analysis. If not, please explain why PEC has not conducted such an analysis or study.

Response:

Yes, the "Progress Energy Carolinas 2012 Generation Reserve Margin Study" prepared by Astrape Consulting for DEP's 2012 IRP (attached hereto as Exhibit 2) included the benefit of being interconnected to neighboring utilities such as TVA, Southern, PJM and SCANA. The reserve margin requirements for DEP would have been substantially higher in this study had these utilities' resources not been taken into account. Furthermore, the goal of the IRP process is to meet customer needs for a reliable supply of electricity at the lowest reasonable cost. The plan that has been identified as the preferred plan then serves as a benchmark against which purchased power opportunities are measured. Before proceeding with a self-build option, it must be determined whether there are any purchased power alternatives available that would maintain the system reliability level in a more cost-effective manner. Depending on the circumstances, DEP generally solicits the

wholesale market before making resource decisions. Such an evaluation could include a formal or informal RFP to evaluate the feasibility of purchasing equivalent generation resources from the wholesale market. DEP evaluates the cost, reliability, flexibility, environmental impacts, risk factors, and various operational considerations in determining the optimal resource addition for a given situation. DEP will continue to evaluate the wholesale market and will utilize purchased power options when they are cost-effective options to reliably meet its customers' needs. The discussion of multi-area modeling begins on page 31 of the attached Exhibit 2.

Request No. 18:

A theme repeated by scores of the witnesses at the public hearings is that climate change is an imminent threat to the survival of the planet, that continued reliance on existing fossil fuel fired and nuclear plants is a major contributor to this threat, that generation from these fuel sources should be supplanted with renewables, demand response, and energy efficiency and that it is imperative that the Commission order steps in this proceeding to accomplish this transition. Please address.

Response:

There continues to be debate regarding global climate change and legislation/regulation associated with addressing this concern. The Companies continue to closely monitor the discussion and possible actions associated with global climate change as it occurs. The Companies believe that the appropriate setting to address global climate change initiatives is in the state and federal legislative process. At this time, the debate continues at the state and federal level, but with no approved legislation/regulations or expected timing of legislation/regulations. When and if legislation or regulations are established, the Companies will comply. Since 2005, DEC and DEP have significantly reduced their carbon footprint from 77M tons to 57M tons of CO2, collectively. The major drivers are that the majority of the Companies' new assets are gas-fired, which reduces carbon emissions by approximately 50% on a per MWh basis as compared to coal-fired assets. In preparation for possible global climate legislation/regulation, the Companies have included assumptions of a carbon-constrained future in the portfolios analyzed in the 2012 IRPs. Since 2006, both DEC and DEP have included a carbon price as part of its integrated resource planning process. While DEC and DEP have had different assumptions regarding the price and timing of CO2 is this timeframe, the impact has been the same – such action anticipates national regulation of carbon emissions and factors the resulting price signal for carbon into the planning process. Such assumptions have contributed to the decisions to retire coal plants, thus reducing the companies' carbon emissions as noted above.

As to the public witness comments that "continued reliance on existing fossil fuel fired and nuclear plants is a major contributor to this threat, that generation from these fuel sources should be supplanted with renewables, demand response, and energy efficiency and that it is imperative that the Commission order steps in this proceeding to accomplish this transition," the Companies note, as they did in their Reply Comments

filed in this Docket, that such assertions may be interesting exercises if the State of North Carolina wants to attempt to maximize EE, DSM and renewable resources, while eliminating baseload nuclear, coal and natural gas generation, without regard to cost, reliability or availability. The Companies submit, however, that these assertions are not realistic proposals if the State of North Carolina wants to ensure reliable and affordable electricity are available to the residential, commercial and industrial customers over the IRP planning horizon, as the Companies are obligated to do. Renewable resources, EE and DSM are important and increasingly significant components of DEC and PEC's IRPs, but they simply cannot realistically be relied upon in the almost exclusive nature that some public witnesses seem to believe. The Companies' 2012 IRPs present robust and balanced portfolios of diverse supply and demand side resources that will cost-effectively and reliably serve customers' short and long-term needs across a range of many possible future scenarios.

Request No. 19:

Another theme of public witnesses was that emissions from coal fired plants is a significant contributor to respiratory illnesses such as asthma. Please address.

Response:

DEC and DEP's coal fired plants comply with state and federal air regulations and permits. The Clean Air Act identifies two types of national ambient air quality standards. *Primary standards* provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. *Secondary standards* provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings.

DEC and DEP's generation assets comply with these regulations and achieve emissions rates well below those that are included in its air permits which protect these standards.

Exhibit No. 1
Docket No. E-100, Sub 137

2012

Duke Energy Carolinas 2012 Generation Reserve Margin Study

Astrape Consulting
8/17/2012

Contents

Executive Summary

The reserve margin study performed by Astrape Consulting was requested by Duke Energy Carolinas in response to North Carolina Utilities Commission Order dated October 26, 2011 in Docket No. E -100, Sub 128. The Order requires DEC to perform a comprehensive reserve margin study and include it as part of its 2012 biennial IRP report.

The optimal planning reserve margin for Duke Energy is based on providing an acceptable level of physical reliability and minimizing economic costs to customers. Customers generally expect power to be available 24 hours a day, 365 days a year, but it is economically unreasonable for a load serving entity to maintain enough reserves to meet this expectation. From a physical reliability perspective, Loss of Load Expectation (LOLE) decreases as reserve margin increases. The most common physical metric used in the industry is to target a system reserve margin that meets the one day in 10 year standard which is interpreted as one firm load shed event every 10 years (LOLE = 0.1). A firm load shed event occurs when load plus spinning reserves is greater than available capacity and all options including market purchases and demand response have been exhausted. This results in unserved energy for a firm customer. From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. The economic optimum is defined as the point where the cost of additional reserves plus the cost of reliability events on customers is minimized. For this study, reserve margin is defined as the following:

- Reserve Margin = (Resources – Demand) / Demand
  - Demand is the Average Summer System Peak Load and has not been reduced by Demand Response
  - Resources are defined based on summer ratings and include Demand Response
  - The solar capacity within the study was given a 50% capacity credit while wind was given a 15% capacity credit (consistent with the 2011 IRP)

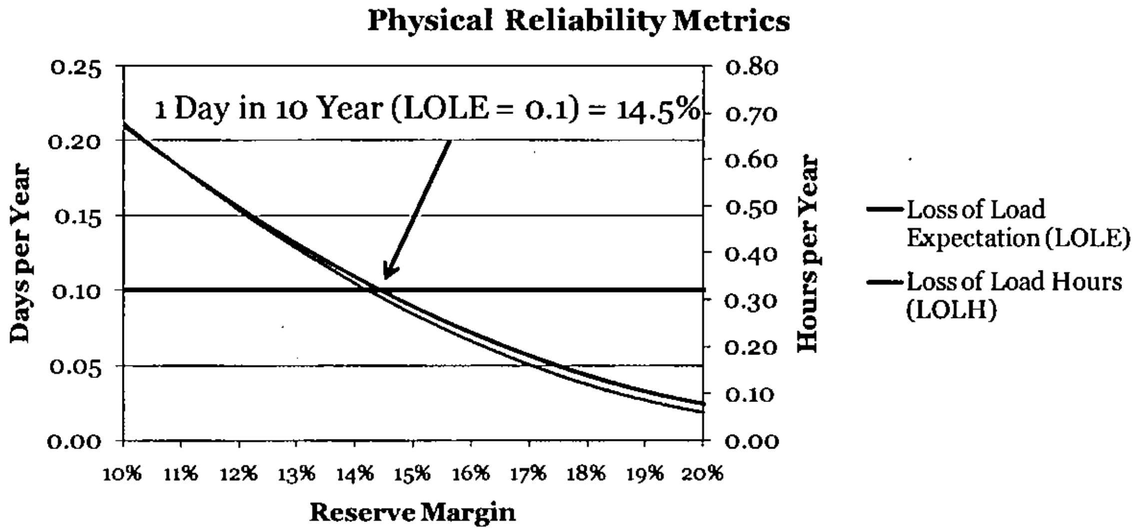
Astrape Consulting has taken a stochastic approach in modeling the uncertainty of weather, economic load growth, unit availability, hydro availability, and transmission availability for emergency tie assistance. Utilizing a multi-area reliability model called SERVM (Strategic Energy and Risk Valuation Model), over 1 million yearly simulations were performed at various reserve margins to calculate the physical reliability metrics and corresponding expected reliability costs. The physical metrics and reliability costs were used to determine an optimal planning reserve margin.

From an economic perspective, the study defines the capacity costs as the annual carrying costs associated with the marginal resource which for this study is a new natural gas combustion turbine. The study defines reliability energy costs as any energy costs the system experiences above the dispatch cost of the marginal resource. These costs include the dispatch of expensive peaking resources such as oil CTs, net imports of expensive market purchases during capacity shortages, and the societal cost of unserved energy.

Summary of Results and Key Insights

The reserve margin that results in 1 day in 10 year LOLE (0.1 days per year) is 14.5% as shown in Figure ES1. Loss of load hours (LOLH) approaches 0.30 hours per year at the 14.5% reserve margin.

Figure ES1. Physical Reliability Metrics



In resource adequacy simulations, firm load shed events are sensitive to inputs due to their infrequent nature. Weather diversity, transmission availability, neighbor reserve levels, and emergency hydro assumptions can shift the 0.1 LOLE reserve margin by several percentage points as shown in the sensitivity section of the report. As an example, emergency hydro assumptions impacted Duke's system LOLE substantially. If the portion of the 1,100 MW hydro capacity that is designated as emergency capacity is available to be used a few hours a month, then the target LOLE reserve margin shifts from 14.50% to 11.25%. This emergency designated block varies by year and month, but during drought conditions, it represents 700-750 MW of unavailable capacity as seen in 2007 and 2008. From a planning perspective, it is difficult to assess the availability of this capacity during drought conditions, and given experience in recent drought years such as 2007 and 2008, it is not prudent to expect this capacity to be available during peak conditions. However, by approaching resource adequacy planning from a more holistic perspective, the target reserve margin is not as sensitive to individual inputs. For this reason, we recommend assessing the economics in addition to the physical reliability metrics. This allows planners to not only assess the comprehensive benefits of incremental capacity, it also allows for better calibration of physical reliability metrics.

The economic reliability assessment which balances the costs and benefits of incremental capacity is seen in Figure ES2 which demonstrates that the long-term minimum cost reserve margin is 14%. As reserve margin increases, the CT carrying costs rise and the reliability energy costs made up of production costs above a CT, net imports above a CT, and expected unserved energy decrease. Between 14% and 16%, the flatness of the curve indicates that there is not a significant cost impact to being slightly above the minimum cost point. Since resource additions are too large to perfectly target a reserve margin, some years will inevitably result in reserve margins that are higher than the average economic optimum. The expected financial impact of these additions is not substantial, since the capacity above the weighted average target also brings some financial benefit. For example, the annual expected difference in cost between the 14% reserve margin and 16% reserve margin is only $9 million and can provide substantial risk benefit.

Figure ES2. Minimum Weighted Average Cost Reserve Margin

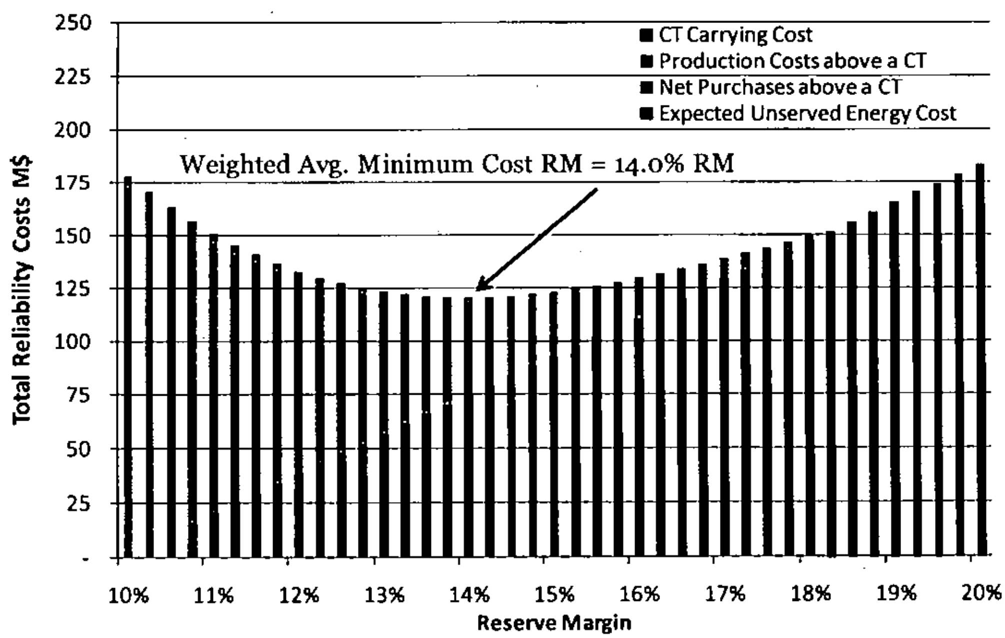
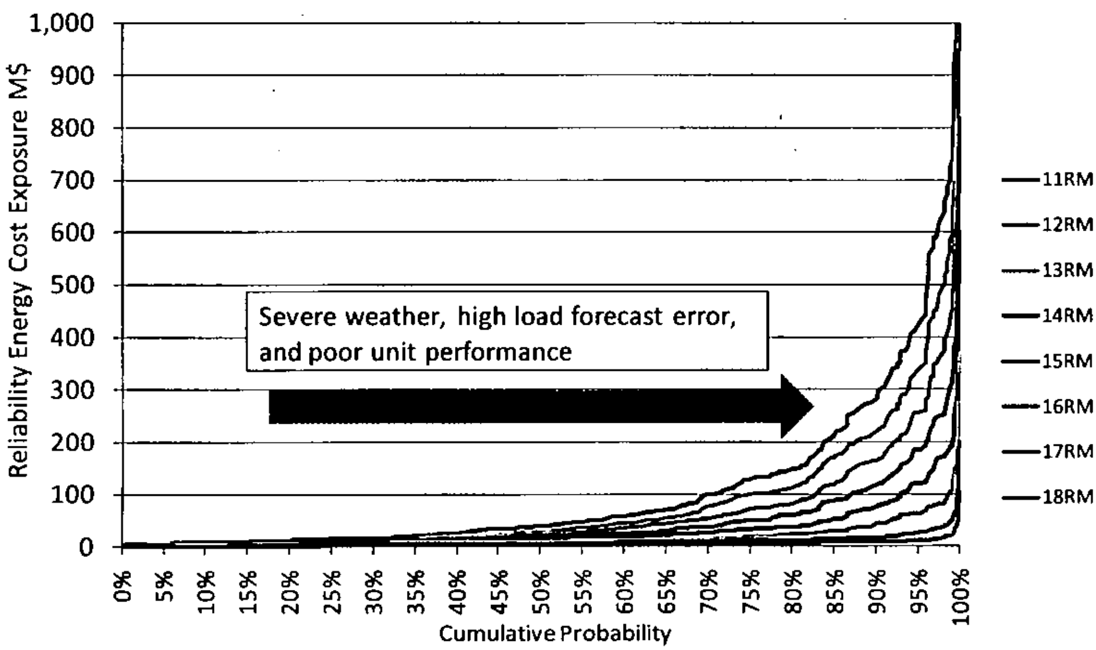


Figure ES3 demonstrates the distribution of reliability energy costs seen in Figure ES2 at each reserve margin level. It should be noted that even at the economic optimum reserve margin of 14% there is still potential for high reliability cost years due to abnormal weather, economic growth, or poor unit performance in the region as shown in the following figure. At a 14% reserve margin, there is a 5% chance that reliability energy costs could exceed $185 million in any given year and a 1% chance that it could exceed $303 million.

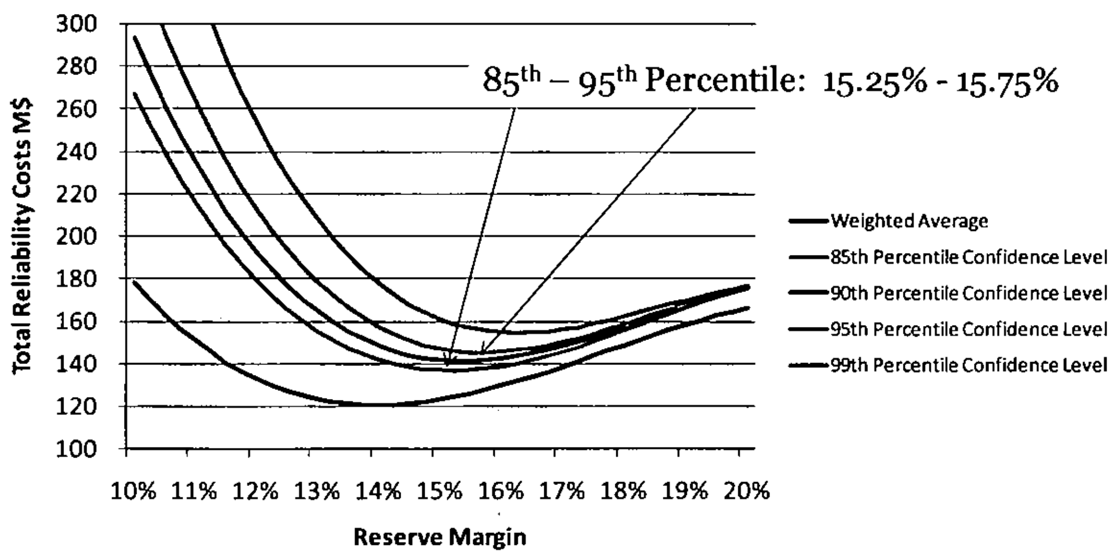
Figure ES3. Distribution of Reliability Energy Costs



Next we examined the optimal economic reserve margin recognizing the different risk profile of energy costs and capacity costs. By comparing capacity costs to reliability energy costs during years with extreme weather or poor unit performance as seen in Figure ES3, we assessed the tail benefit of additional capacity. The reliability energy costs seen in Figure ES3 were taken at different confidence levels (85%, 90%, 95%, and 99% probabilities) and added to the fixed capacity costs at each reserve margin to form the confidence level curves in Figure ES4. This assessment showed that in 10% of all scenarios, Duke

Energy would receive an economic benefit by adding efficient natural gas turbines up to a reserve margin of 15.50%. This is shown by the 90% confidence level curve in Figure ES4. As stated previously, when we review the weighted average curve in the same figure we can see that by adding capacity to achieve a 16% reserve margin versus a 14% reserve margin, average annual costs only increase by $9 million, but the additional capacity acts as an insurance product to customers. In fact, 10% of the time customers would see their cost exposure decrease by at least $70 million in any given year as seen in Figure ES3.

Figure ES4. Optimal Reserve Margins over a Range of Confidence Intervals



Recommendation

Astrape recommends that Duke set its absolute minimum reserve margin at the 14.5% LOLE target (LOLE = 0.1) and recommends a target of 15.50% based on the 90% confidence level economic target. Since capacity is added in large blocks to take advantage of economies of scale, the actual reserve margin will often be somewhat higher than the target threshold of 15.5%. As shown in the charts and data above, a reserve margin target in the range of 14.5% to 16% produces similar total customer costs whether at the low end or high end of the range. To accommodate large resource additions such as nuclear, coal, or even larger combined cycle resources, the reserve margin would likely rise above the top end of the reserve margin range. However, the additional production cost and economy of scale benefits provided by such resources would likely justify their addition. Therefore, the recommended target reserve margin of 15.50% with a range of 14.5% to 16% should not be considered absolute as all resource decisions should be made on a case-by-case basis.

I. List of figures

II. List of tables

III. Input Assumptions

A. Study Year

The selected study year is 2016. The year 2016 was chosen because it is three to four years into the future which is indicative of the amount of time needed to permit and construct a new generating facility. By looking three to four years out, this study reflects a longer term optimal reserve margin. Lower economic load forecast error as well as surrounding market conditions could potentially allow the company to carry slightly lower reserves in the short term.

Although 2016 was selected for the base case simulations, the SERVM simulation results should apply for the 3 to 5 year period following 2016 assuming that resource mixes and market structures do not change drastically over that term. To that end, several sensitivities were run to reflect changes in the market that could occur in this time period as well as a look at a 2023 Study Year.

B. Load Modeling

Table 1. 2016 Load Forecast

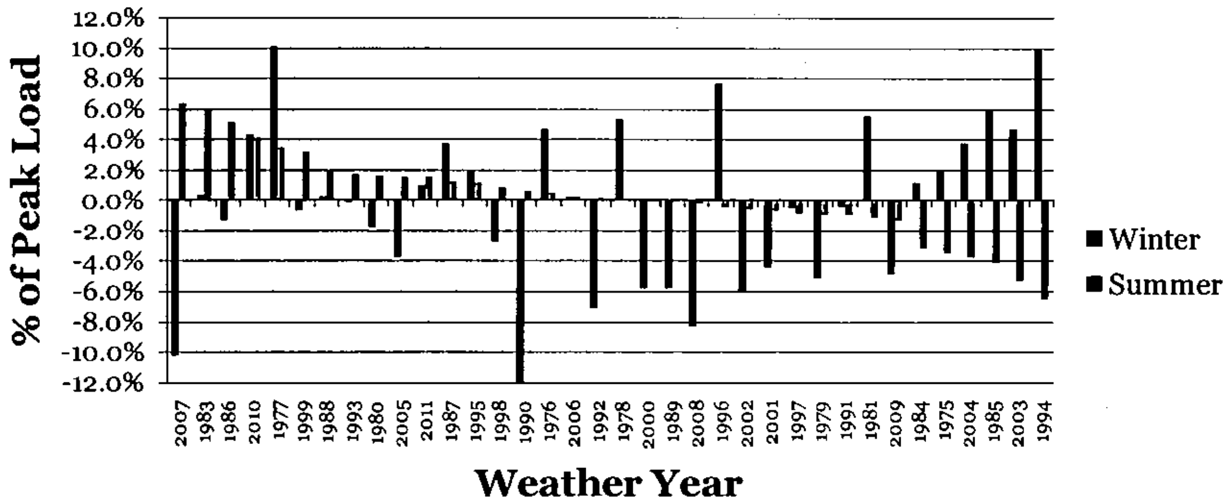
Month	Energy (MWh)	Peak Load (MW)
January	9,163,558	18,891
February	8,191,438	18,033
March	7,845,982	16,797
April	7,311,837	14,012
May	7,885,201	16,407
June	9,015,082	18,675
July	9,509,029	19,476
August	9,595,229	19,075
September	8,256,070	17,595
October	7,486,890	14,687
November	7,541,890	16,048
December	8,669,874	17,756

Table 1 displays the peak and energy forecasts for 2016 under normal weather conditions. The company is expected to have a winter peak of 18,891 MW and a summer peak of 19,476 MW. All values include the reduction for energy efficiency but exclude any other DSM reductions.

To model the effects of weather uncertainty, 37 historical weather years were developed to reflect the impact of weather on load. A neural network program was used to develop relationships between weather observations and load based on the last five years of historical weather and load. Different relationships were built for each month of the year using hourly temperature, time of day, day of week, 8 hour prior temperature, 24 hour prior temperature, 48 hour prior temperature, and heating and cooling degree hours.

These relationships were then applied to the last 37 years of weather to develop 37 load shapes for 2016. Equal probabilities were given to each of the 37 load shapes in the simulation. Figure 1 ranks all weather years by peak summer load for the system. In the most severe weather conditions, the summer peak can be approximately 6% higher than the peak under normal weather conditions and 10% for the winter. The reason for the larger variation in winter loads is the larger variation of temperature versus normal weather of 10 to 13 degrees whereas in the summer maximum variation versus normal weather is only 6 degrees.

Figure 1. Peak Load Variability Vs. Normal Weather



The difference in frequency of high load periods during winter versus summer can be seen in Figure 2. The duration of high load is far less in the winter causing the summer to have higher reliability risk. So despite higher variation in winter peak loads, sustained high loads in the summer cause the majority of reliability events.

Figure 2. Frequency of High Load Hours for Winter and Summer

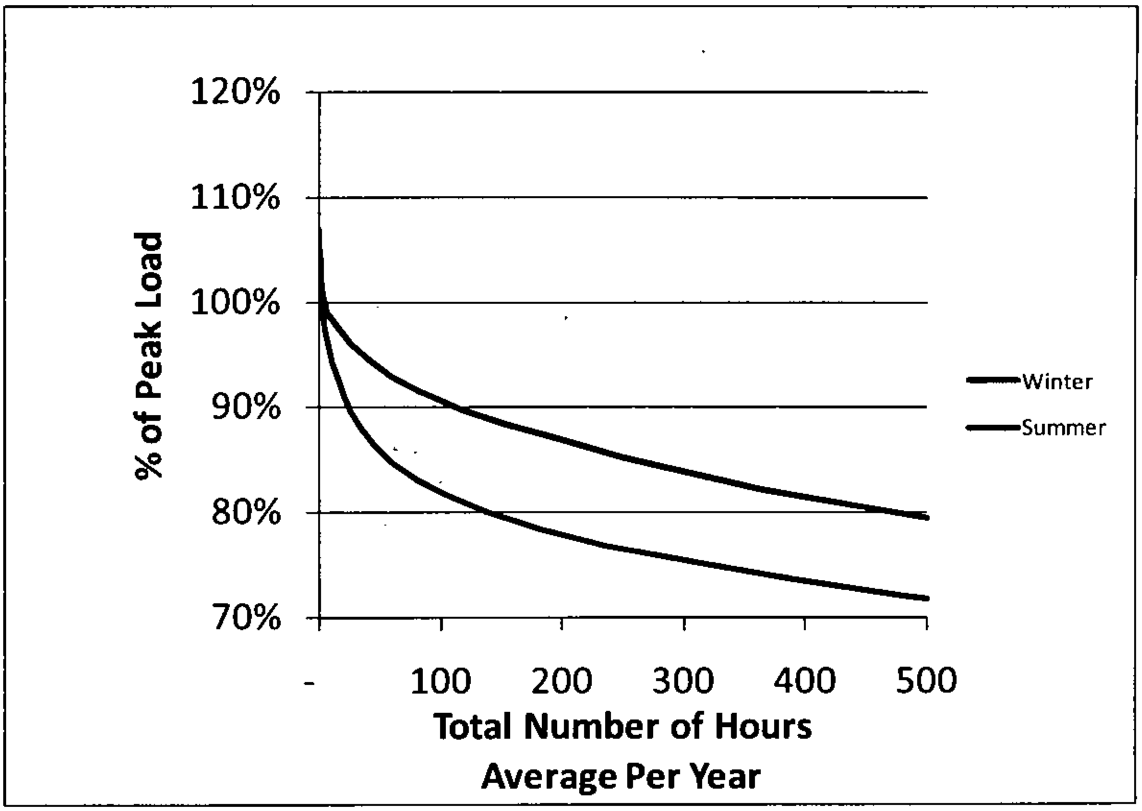


Table 2 summarizes the combined summer and winter peaks by weather year. The table shows that recent years including 2007 and 2010 were among the most severe summers.

Table 2. 2016 Peak Load Rankings for All Weather Years

Summer Peaks

Max	20,721	6.40%
Forecast	19,476	

Winter Peaks

Max	20,798	10.1%
Forecast	18,891	

Rank	Year	Peak	Versus Forecast (%)	Rank	Year	Peak	Versus Forecast (%)
1	2007	20,721	6.4%	1	1977	20,798	10.1%
2	1983	20,634	5.9%	2	1982	20,798	10.1%
3	1986	20,485	5.2%	3	1994	20,778	10.0%
4	2010	20,289	4.2%	4	1996	20,347	7.7%
5	1977	20,156	3.5%	5	1985	20,015	5.9%
6	1999	20,106	3.2%	6	1981	19,944	5.6%
7	1988	19,856	2.0%	7	1978	19,902	5.4%
8	1993	19,808	1.7%	8	2003	19,790	4.8%
9	1980	19,789	1.6%	9	1976	19,777	4.7%
10	2005	19,777	1.5%	10	2010	19,713	4.3%
11	2011	19,772	1.5%	11	1987	19,614	3.8%
12	1987	19,729	1.3%	12	2004	19,605	3.8%
13	1995	19,702	1.2%	13	1995	19,259	1.9%
14	1998	19,645	0.9%	14	1975	19,254	1.9%
15	1990	19,600	0.6%	15	1984	19,121.20	1.2%
16	1976	19,583	0.6%	16	2011	19,082	1.0%
17	2006	19,533	0.3%	17	1983	18,950	0.3%
18	1992	19,517	0.2%	18	2006	18,947	0.3%
19	1978	19,492	0.1%	19	1988	18,934	0.2%
20	2000	19,462	-0.1%	20	1993	18,884	0.0%
21	1989	19,461	-0.1%	21	1991	18,823	-0.4%
22	2008	19,429	-0.2%	22	1997	18,801	-0.5%
23	1996	19,388	-0.4%	23	1999	18,761	-0.7%
24	2002	19,362	-0.6%	24	1986	18,650	-1.3%
25	2001	19,345	-0.7%	25	1980	18,561	-1.7%
26	1997	19,317	-0.8%	26	1998	18,383	-2.7%
27	1979	19,300	-0.9%	27	2005	18,192	-3.7%
28	1991	19,288	-1.0%	28	2001	18,068	-4.4%
29	1981	19,247	-1.2%	29	2009	17,969	-4.9%
30	2009	19,225	-1.3%	30	1979	17,929	-5.1%
31	1984	18,859	-3.2%	31	2000	17,809	-5.7%
32	1975	18,797	-3.5%	32	1989	17,807	-5.7%
33	2004	18,750	-3.7%	33	2002	17,745	-6.1%
34	1985	18,670	-4.1%	34	1992	17,551	-7.1%
35	2003	18,446	-5.3%	35	2008	17,325	-8.3%
36	1994	18,202	-6.5%	36	2007	16,953	-10.3%
37	1982	17,849	-8.4%	37	1990	16,130	-15%

From an annual energy perspective, the following table shows the top 10 highest weather years. Table 3 shows that 2010 had energy consumption 5% higher than normal as both winter and summer seasons were severe. The second highest weather year was only 2.5% higher than average energy.

Table 3. Weather Years Ranked by Total Energy

Annual Energy
Top 10

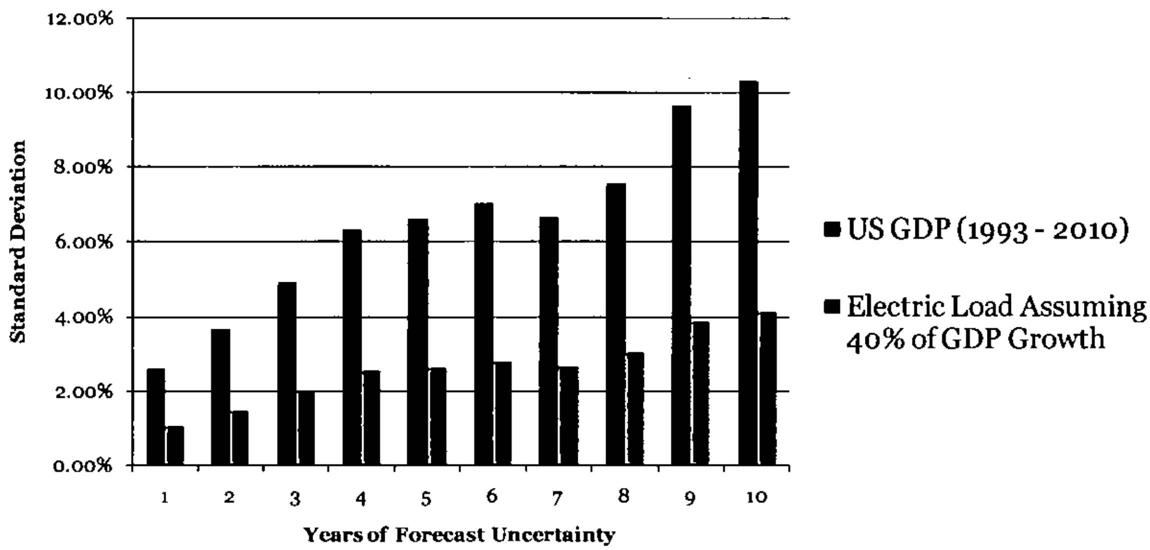
Max	106,073,456	5.0%
Forecast	101,065,715	

Rank	Year	Peak	Versus Forecast (%)
1	2010	106,073,456	5.0%
2	1977	103,627,852	2.5%
3	1993	103,014,691	1.9%
4	1980	102,568,028	1.5%
5	1987	102,319,099	1.2%
6	1978	102,300,173	1.2%
7	1986	102,249,879	1.2%
8	2007	102,241,193	1.2%
9	1981	102,065,451	1.0%
10	1988	101,879,158	0.8%

C. Load Forecast Error

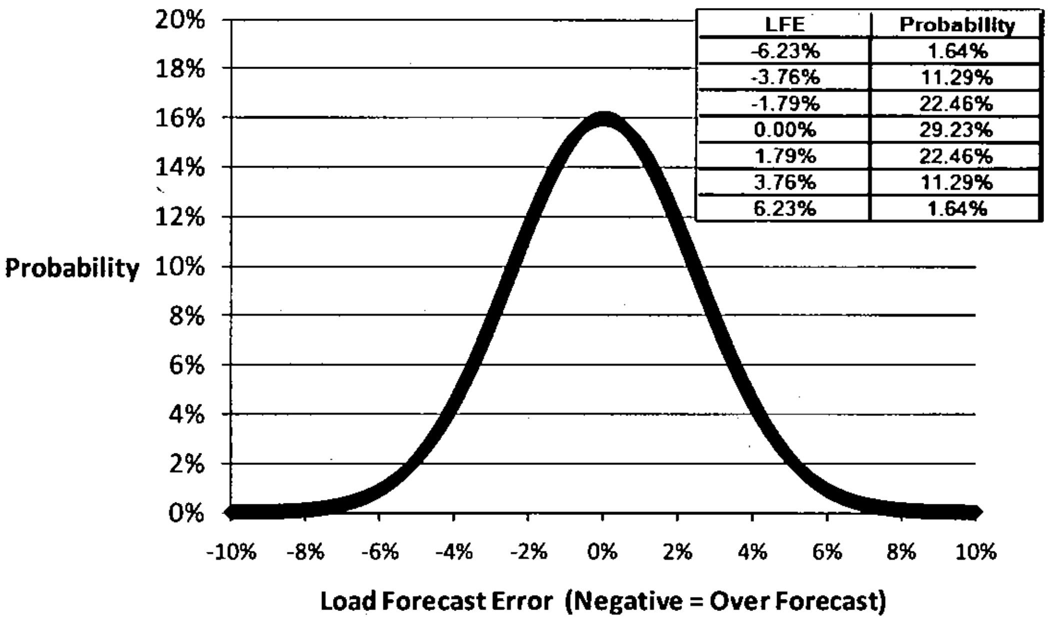
An analysis was performed using the historical Congressional Budget Office four year prior forecasts of GDP and comparing those forecasts to actual data from 1993 – 2010. Comparing how well GDP was predicted four years in advance provides insight into the economic uncertainty that should be applied to utility loads. The chart below shows the standard deviation of historical GDP forecast error for forecasting one to ten years in advance. As expected, the standard deviation of forecast error increases as the number of years increase. Based on discussions with Duke, electric load is assumed to grow at about 40% of GDP growth. Assuming four year forecast error, standard deviation for load forecast error uncertainty for utility load is 2.5% as shown in the following figure. If lead times for new generation changed substantially, then the standard deviation used to develop the economic load forecast error would need to be adjusted accordingly. However, it is unlikely that typical generation resources can be installed and brought in-service in less than three to four years given the time needed for environmental and regulatory approvals, construction, and startup testing.

Figure 3. Standard Deviation of GDP forecast error (1 to 10 Year Projections)



Astrape also performed a comparison of the company's historical four year prior forecasts to actual weather normalized load. Astrape observed that in recent years there was a tendency to over forecast given the economic downturns seen in the last decade. However, the standard deviation of load forecast error was 3.34%, which was in the range of the CBO study. The company and Astrape determined that using 2.5% was a reasonable value for the standard deviation and Astrape developed a normal distribution as shown in the following Figure 4. The continuous distribution was converted into a discrete distribution with the 7 points shown for use in determining discrete scenarios to be modeled. As an example of how to interpret the economic uncertainty data, there is a 1.64% chance that load will be 6.23% greater than forecasted.

Figure 4. Load Forecast Error



LFE	Probability
-6.23%	1.64%
-3.76%	11.29%
-1.79%	22.46%
0.00%	29.23%
1.79%	22.46%
3.76%	11.29%
6.23%	1.64%

SERVM utilized each of the 37 weather years and applied each of these seven load forecast error points to create 259 different load scenarios.

D. Resources

The resources and seasonal capacities for the 2016 study are shown in the following tables.

Table 4. Nuclear Resource Capacities (MW)

Unit Name	January	July
Catawba 1	891	857
Catawba 2	881	847
McGuire 1	900	844
McGuire 2	900	844
Oconee 1	875	856
Oconee 2	875	856
Oconee 3	875	856
Totals	6,196	6,196

Table 5. Baseload and Intermediate Resource Capacities (MW)

Unit Name	January	July
Allen 1	167	162
Allen 2	167	162
Allen 3	270	261
Allen 4	282	276
Allen 5	275	266
Belews Creek 1	1135	1110
Belews Creek 2	1135	1110
Cliffside 5	562	556
Cliffside 6	825	825
Marshall 1	380	380
Marshall 2	380	380
Marshall 3	658	658
Marshall 4	660	660
Buck CC	508	500
Buck CC Duct	120	120
Dan River CC	508	500
Dan River CC Duct	120	120
CPL SOR A	2	2
CPL SOR D	3	3
CPL SOR E	2	2
NUG	26	26
Totals	8,185	8,079

Retired by 2016
Buck 3
Buck 4
Buck 5
Buck 6
Cliffside 1
Cliffside 2
Cliffside 3
Cliffside 4
Dan River 1
Dan River 2
Dan River 3
Riverbend 4
Riverbend 5
Riverbend 6
Riverbend 7

Table 6. Peaking Resource Capacities (MW)

Unit Name	January	July
Lee 1 NG	100	100
Lee 2 NG	100	102
Lee 3 NG	170	170
Lee CT1	41	41
Lee CT2	41	41
Lincoln CT1	93	79.2
Lincoln CT2	93	79.2
Lincoln CT3	93	79.2
Lincoln CT4	93	79.2
Lincoln CT5	93	79.2
Lincoln CT6	93	79.2
Lincoln CT7	93	79.2
Lincoln CT8	93	79.2
Lincoln CT9	93	79.2
Lincoln CT10	93	79.2
Lincoln CT11	93	79.2
Lincoln CT12	93	79.2
Lincoln CT13	93	79.2
Lincoln CT14	93	79.2
Lincoln CT15	93	79.2
Lincoln CT16	93	79.2

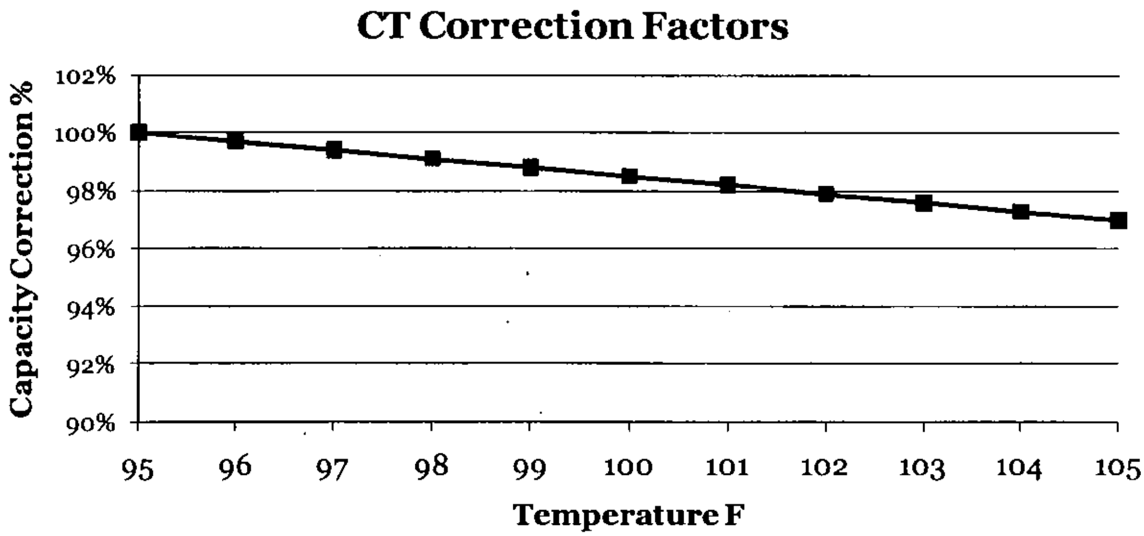
Unit Name	January	July
MillCreek CT1	92	74
MillCreek CT2	92	74
MillCreek CT3	92	74
MillCreek CT4	92	74
MillCreek CT5	92	74
MillCreek CT6	92	74
MillCreek CT7	92	74
MillCreek CT8	92	74
Rockingham CT1	165	165
Rockingham CT2	165	165
Rockingham CT3	165	165
Rockingham CT4	165	165
Rockingham CT5	165	165
Anson Hamlet CT	4	4
CPL Peaking CT	2	2
IRP CT 1	900	740
IRP CT 2*	0	740
Totals	4,410	4,628

Retired by 2016
Buck CT1
Buck CT2
Buck CT3
Buzzard Roost CT1
Buzzard Roost CT2
Buzzard Roost CT3
Buzzard Roost CT4
Buzzard Roost CT5
Buzzard Roost CT6
Buzzard Roost CT7
Buzzard Roost CT8
Buzzard Roost CT9
Buzzard Roost CT10
Dan River CT1
Dan River CT2
Riverbend CT1
Riverbend CT2
Riverbend CT3
Riverbend CT4

*IRP CT 2 is in service in June, 2016

All summer ratings in the previous tables are based on 95 degree F. On an hourly basis, SERVM can adjust the capacity of each resource based on the historical hourly temperature for the weather year being modeled. Because the maximum output of peaking units degrades as temperatures increase, the derating multipliers in Figure 5 were utilized to derate the units above 95 F. The multipliers were developed based on the Duke CT fleet which assumes a degradation of 0.3% of capacity per degree. This ensures correlation of capacity output with load since both are highly dependent on the hourly temperature.

Figure 5. Summer Rating Capacity Multipliers



The hydro portfolio is modeled in segments that include Run of River (ROR), Scheduled (Peak Shaving), and Emergency Capacity. The Run of River segment is dispatched as base load capacity providing its designated capacity every hour of the year. The scheduled hydro is used for shaving the daily peak load but also includes minimum flow requirements. If included, the emergency capacity is used only to prevent firm load shed and the model allows the emergency mode to "borrow" energy from the future dispatch of the scheduled hydro portion with the constraint that the energy amount is enough for only a few hours. Typically hydro resources are not able to be dispatched at their nameplate capacity during peak hours due to water constraints or river flow requirements as seen in 2008. By modeling the hydro resources in these three segments, the model captures the appropriate amount of capacity dispatched during peak periods. See the confidential Appendix for the details regarding hydro capacities.

Figure 6 shows the total breakdown of scheduled versus emergency hydro based on the last 37 years of weather. Out of the total 1,100 MW of capacity owned by the company, only 442 MW on average is dispatched during peak periods. During drought years, less than 390 MWs are dispatched on peak in specific months. For this reason, the use of emergency hydro was not included in the base case results due to recent experience, but a sensitivity was performed that included the additional emergency hydro capacity which could be utilized for a few hours per month.

Figure 6. Scheduled Capacity versus Emergency Capacity

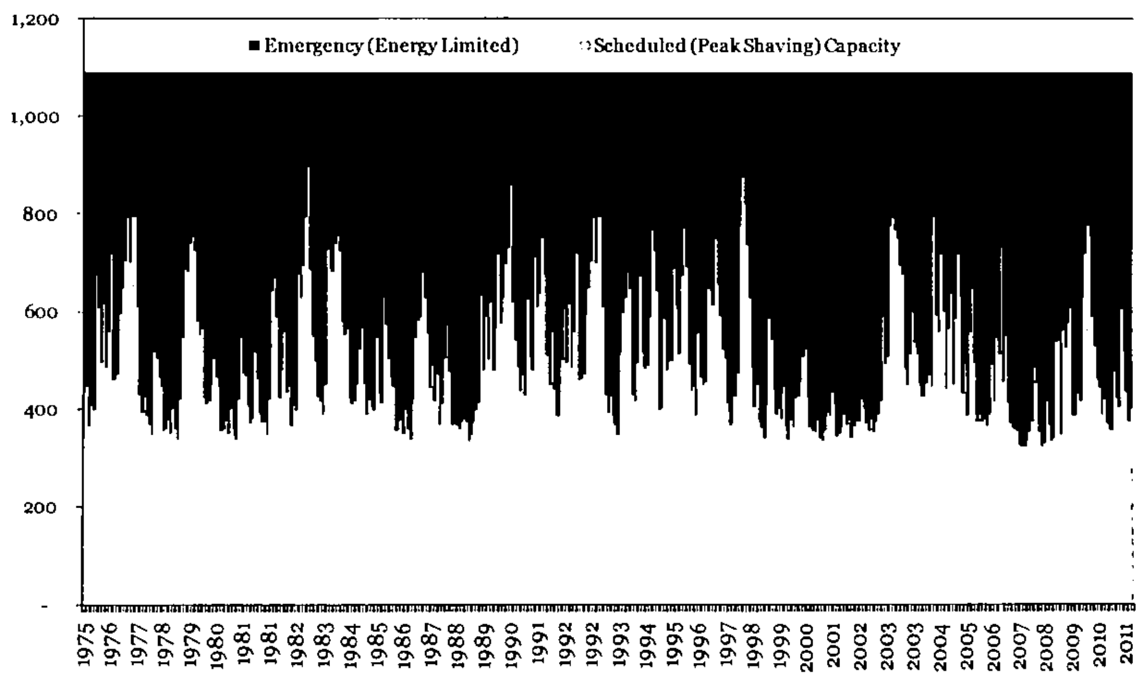


Figure 7 demonstrates the variation of hydro energy by weather year which is input into the model. The drought shown in 2001, 2007, and 2008 is captured in the reliability model.

Figure 7. Hydro Energy by Weather Year

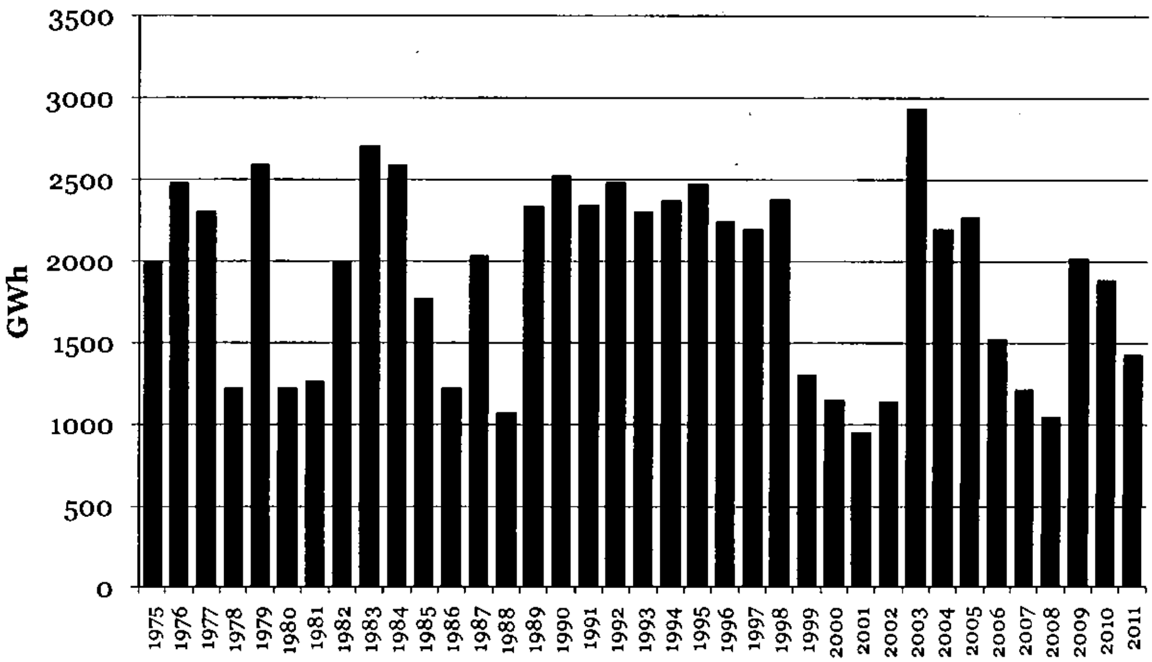


Figure 8 compares actual history of the dispatch level of the hydro resources for a 2008 and 2009 as a percentage of time versus how the model dispatches the resources. The figure demonstrates the drought conditions that were seen in 2008 and also shows that the model is capturing a realistic dispatch of the hydro resources.

Figure 8. Hydo Dispatch Calibration: Percent of Time above Capacity Threshold

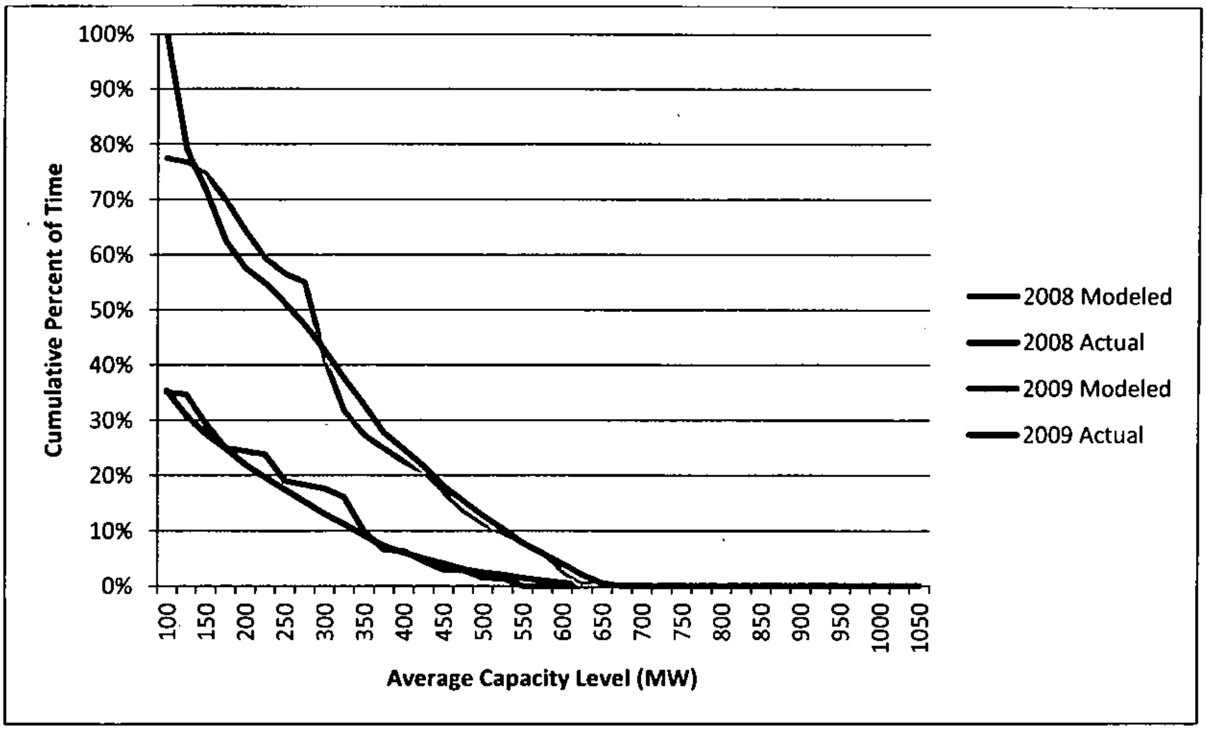


Table 7. Pump Storage Resources

Unit Name	January	July	Reservoir Capacity (MWh)	Reservoir Generating Hours
Bad Creek	1360	1360	33,030	24
Jocasse	780	780	57,540	74

Total	2140	2140

Pumping for pumped storage occurs anytime energy is available. During constrained periods, pumped storage resources are given dispatch priority to maintain a maximum level in the storage ponds. During less constrained periods, the dispatch order is switched so that the energy is used before CT's are dispatched. SERVM uses any excess capacity to fill up the ponds including economic purchases from the market. In actual practice, this process may be performed slightly differently to minimize production cost during off-peak periods. However, the model architecture is appropriate for reliability modeling, because it is always economic to build up the reservoirs of storage units with any generating asset available if that is what is required to have the units available to operate to avoid unserved energy.

Table 8. Renewable Resources

Unit Name	January	July
Solar – Nameplate Capacity	49	49
Wind – Nameplate Capacity	318	318
Landfill Gas	32	32
Poultry_PPA	14	14
Biomass_PPA	134	134
Totals	547	547

For reserve margin calculations, Solar capacity is given a 50% capacity credit and wind capacity is assumed to have a 15% capacity credit. For these resources, an 8760 hourly generation shape was used. The average summer and winter shapes are shown in Figure 9 and Figure 10. For each day, SERVM draws a daily shape from all the days in the month. Because historical data is unavailable, this random draw is used for all weather years.

Figure 9. Solar Profile

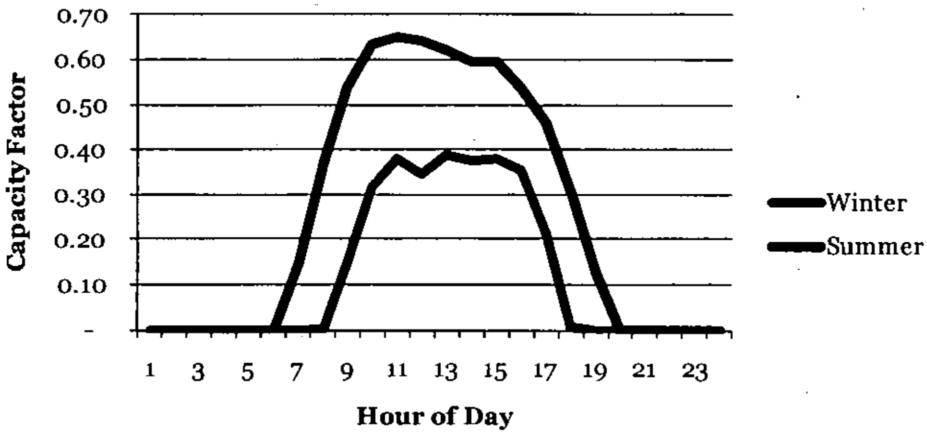
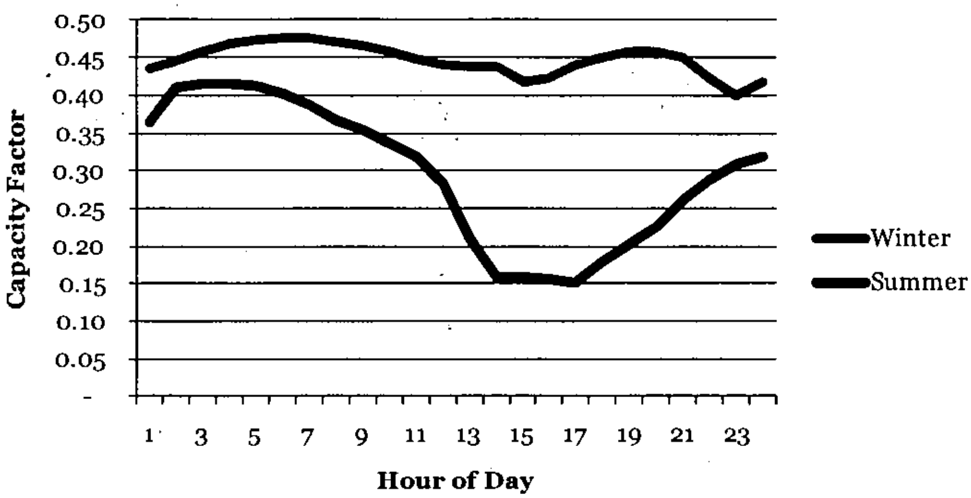


Figure 10. Wind Profile



E. Unit Outage Data

Unlike typical production cost models, SERVM does not use an EFOR for each unit as an input. Instead, historical GADS data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. For this RM Study, 2007-2011 GADS events were entered into SERVM. The events are entered using the following variables:

Full Outage Modeling
Time-to-Repair Hours
Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Percentage - % of full outages that are maintenance outages. SERVM uses this percentage and allows units to remain online until the following weekend if they are needed in the short term.

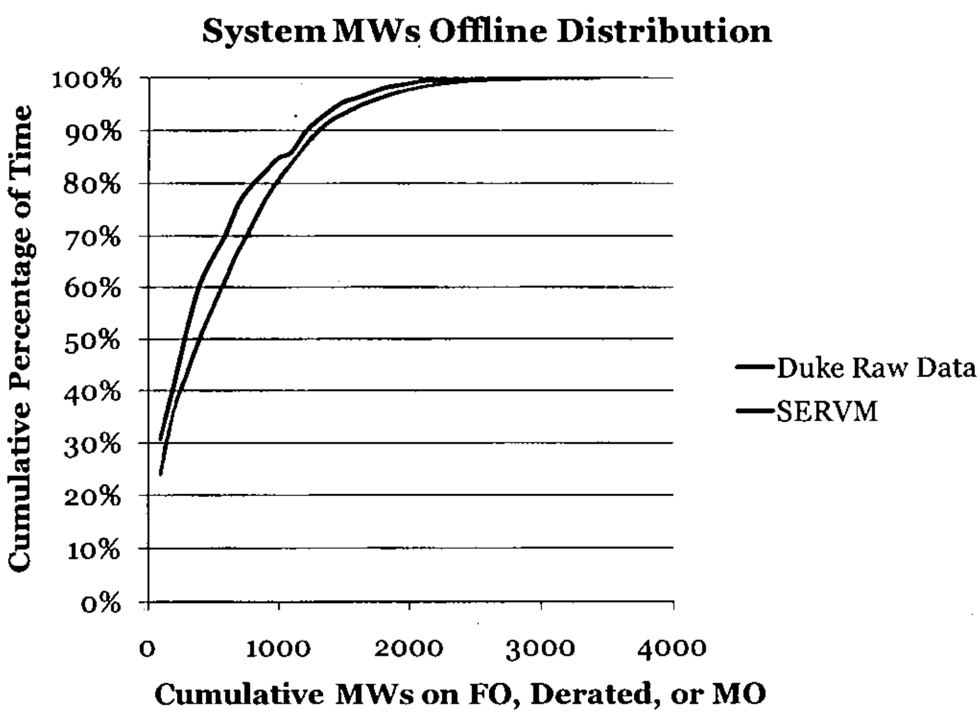
For example purposes, assume that from 2007 – 2011, Allen 1 had 15 full outage events and 30 partial outage events reported in the GADs data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data along with the other variables listed above. These multiple Time-to-Repair and Time-to-Fail distributions are used by SERVM. Because typically there is an improvement in EFOR across the summer, the data is typically broken up into seasons resulting in a set of Time-to-Repair and Time-to-Fail inputs for summer, off peak, and winter based on history. Assume Allen 1 is online in hour 1 of the simulation. SERVM will randomly draw a Time-to-Fail value from the distribution provided for both full outages and partial outages. The unit will run for that amount of time before failing. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new

Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture.

Unit Outage Calibration

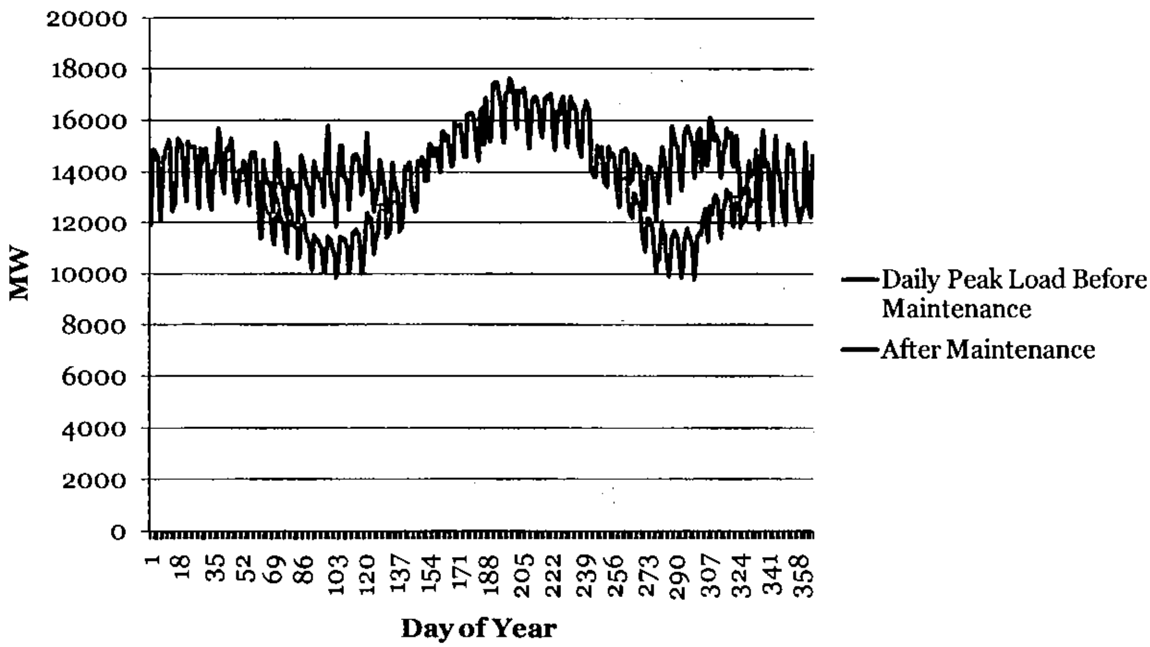
The critical aspect of unit performance modeling for a reliability study is the cumulative MW offline distribution. Most reliability problems are due to significant coincident outages. Figure 11 shows the distribution of outages for Duke Energy. The model has been calibrated to ensure this distribution is captured. Based on the data in the figure 10, the company may have 1,000 MW of capacity offline in 15% of all the hours. This equates to approximately 5% in reserve margin unavailable. System and individual outage rates are located in the confidential Appendix of this report. System and individual outage rates are located in the confidential Appendix of this report.

Figure 11. System Capacity Offline as a Percentage of Time



To capture the impact of planned maintenance, the 2016 maintenance schedule was modeled which removes capacity during the shoulder months of the year. Figure 12 shows that when planned maintenance is assumed in the shoulder months that the resulting load level between winter and shoulder periods is relatively flat.

Figure 12. Daily Peak Load Plus Planned Maintenance Requirement



F. Demand Response

A total of 987 MWs of demand response were modeled in the simulation. Energy efficiency (EE) was directly removed from load in the simulation while the resources in Table 9 were modeled as resources to be called upon given a reliability event. SERVM takes into account the constraints on demand response and dispatches accordingly. These constraints include a maximum number of hours per year, hours per day, days per week, and shadow dispatch price for the resources to be called.

Table 9. Demand Response Summary

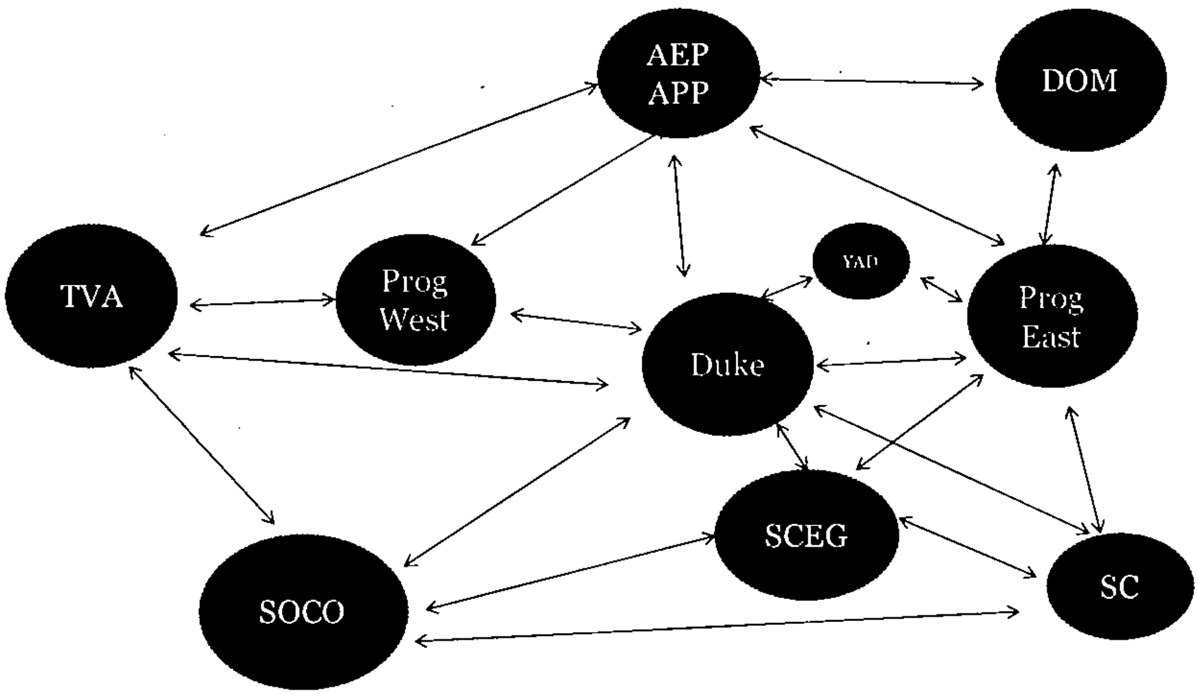
Unit Name	January Capacity	July Capacity	Hours Per Year Limit	Hours Per Day Limit	Days Per Week Limit
PowerManager	0	432	100	10	7
PowerShare0/5	8	9	40	8	7
PowerShare5/5	8	9	40	8	3
PowerShare10/5	8	9	40	8	3
PowerShare15/5	8	9	40	8	3
PowerShare_Mand	381	381	100	10	7
PowerShare_Generator	14	14	100	10	7
PowerShare_IS	111	110	150	10	7
PowerShare_SG	16	16	8760	24	7
Total	552	987			

G. Multi Area Modeling

The surrounding market must play a significant role in resource adequacy even for a utility the size of Duke Energy Carolinas. If several large generators are offline due to outage during peak season, it is likely that the company would depend on market purchases from surrounding regions.

The market representation used in SERVM was developed through consultation with Duke Energy Staff, EIA forms, Company Integrated Resource Plans (IRP), and reviews of NERC resource adequacy assessments. The base case level of reserves for neighbors is based on target reserve margins for surrounding neighbors. Using this methodology ensures that the company is not leaning on an external market more than is reasonable. Figure 13 shows the topology used for the region.

Figure 13. Regional Topology



Each neighbor's hourly loadshape was modeled based on historical hourly temperature data similarly to the Duke load. By using hourly weather, load diversity was captured for each neighboring area. Diversity of peak load is important to understand especially when examining physical reliability metric results. Table 10 shows the average diversity for summer months across all 37 years for each area. These values represent the percentage reduction from peak load that the neighbor is on average experiencing when Duke is experiencing its peak load. To ensure that Duke was not overstating the expectation of weather diversity and therefore available capacity from neighbors, Astrape believed it was prudent to cap the weather diversity in any given peak hour at 3%. A sensitivity assuming no weather diversity was simulated to understand the impact that weather diversity has on lowering the target reserve margin.

Table 10. Neighbor Diversity Factors

	Summer Diversity
SOCO	1.5%
AEP	1.7%
Dominion	1.9%
TVA	1.5%
SCEG	1.3%
Santee Cooper	1.3%
Progress East	1.2%
Progress West	3.3%

Table 11 displays a capacity and load summary of each of the neighbors including its current target reserve margin. The reserve margin calculations in this table assume that the interruptible capacity is included as a resource. While it is recognized that the region currently contains more capacity than these targets, it is not prudent to expect these additional reserves to be available long term. Outage rates for neighboring units were developed using existing Progress and Duke resources sorted by unit type and capacity size. Hydro resources reflect similar dispatch to the Progress and Duke hydro portfolios.

Table 11. Neighbor Capacity, Load, and Target Reserve Margin

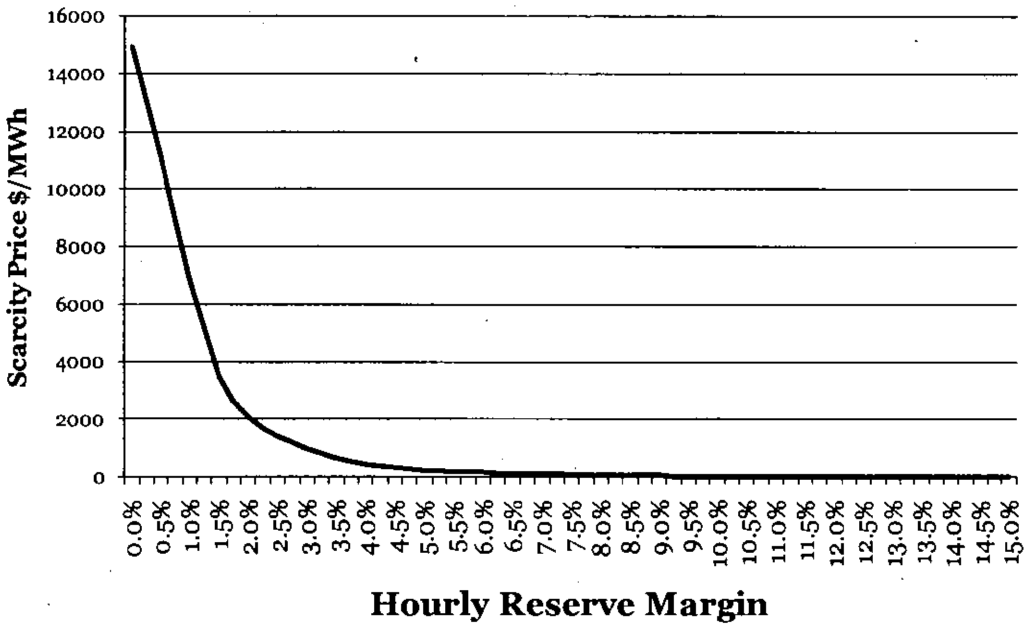
	Progress	Southern Company	Santee Cooper	SCE&G	TVA	AEP_APP	DOM	Yadkin
Nuclear	3,563	6,895	318	2,066	7,832	0	3,501	
Coal and CC*	6,899	37,247	3,974	2,547	19,618	6,155	10,347	
Peaking	4,243	8,943	780	322	5,450	450	4,135	
Hydro	335	2,379	457	240	4,254	554	318	215
Pump Storage	0	1,186	0	576	1,739	238	3,003	
Interruptible	932	2,600	424	225	1,500	0	230	
Total Summer Capacity	15,972	59,249	5,953	5,976	40,393	7,397	21,534	215

Summer Peak Load	13,835	51,101	5,155	5,138	35,000	6,372	18,686
Summer Reserve Margin	15.4%	15.9%	15.5%	16.3%	15.4%	16.1%	15.2%

*includes renewable capacity

The costs of market purchases were calibrated using Duke Energy historical purchases and other market pricing data from the southeast region. As shown in Figure 14, scarcity pricing is based on the shortage in the specific region. As the excess capacity approaches zero, the price of capacity approaches the cost of unserved energy. Such an event is rare but can occur as a function of severe weather, poor unit performance, and significant load forecast error.

Figure 14. Scarcity Pricing Model



Available Transmission Capacity and TRM

The import capability is made up of Available Transmission Capability (ATC) and Transmission Reliability Margin (TRM). ATC is the non firm hourly transmission expected to be available in the market place while TRM is the portion of the transmission system that is held back for reliability needs. TRM is a fixed number while ATC is highly volatile. Due to its highly volatile nature, ATC is represented as a distribution to capture hours when there is little capacity to hours when there is abundance. The distributions used in SERVM are based on historical hours in 2011 during peak periods. It should be noted that these limits do not represent the amount of generation available from neighbors but only serve as the import constraint. Given these constraints, it is expected that the limiting factor will be generation availability from neighbors rather than transmission. However, transmission capability will be a critical sensitivity in the final analysis. See the appendix for details regarding the values used for ATC and TRM.

H. Carrying Cost of Capacity

The cost of carrying incremental reserves was based on the capital cost, fixed O&M, and estimated transmission upgrades of four Advanced CTs with a total summer rating of 740 MW. The cost assumptions were based on estimates provided by Duke Energy. The appendix displays the characteristics and costs of the four CT site used to develop the capacity costs and the avoided and levelized costs by year.

I. Operating Reserve Requirements

Duke provides 500 MW of spinning reserves and 600 MWs of total operating reserves which was implemented into the model.

J. Cost of Unserved Energy

Unserved energy costs were derived based on information from national studies completed for the Department of Energy in 2003 and 2009. The national studies were compilations of other surveys performed by utilities over the last two decades. The national study split the customer classes into residential, small commercial and industrial, and large commercial and industrial. The 2009 study shows higher costs for commercial and industrial consumers compared to 2003. We expect that the costs of outages have risen rapidly in recent history for commercial and industrial customers due to the impact of technology; however both Duke and Astrape questioned the $92.16/kWh values shown in the 2009 Study for Small C&I. Given the magnitude of the values seen in both studies, Astrape and Duke determined that $15,000/MWh was a reasonable base case assumption Due to the infrequent nature of unserved energy; the sensitivity results demonstrate that this assumption is not the main driver of the results.

Table 12. Unserved Energy Costs

	Class Breakdown %	2003 DOE Study 2003$/kWh	2009 DOE Study 2008$/kWh	2003 DOE Study 2016$/kWh	2009 DOE Study 2016$/kWh
Residential	35%	1.15	1.10	1.45	1.27
Small C&I	37%	26.00	79.90	32.79	92.16
Large C&I	28%	15.00	23.80	18.92	27.45
Weighted Average $/kWh				17.93	42.23
Average of Studies $/kWh				30.08	

V. Simulation Methodology

Since most reliability events are high impact, low probability events, a large number of scenarios must be considered. Deterministic selection of extreme events will not give an accurate representation of the operation of any system during such an event, nor would it be possible to estimate a distribution of when such events could occur. For Duke Energy, SERVM utilized 37 years of historical weather and load shapes, 7 points of economic load growth forecast error, and 400 iterations of unit outage draws to represent the full distribution of realistic scenarios. The number of yearly simulation cases equals 37 weather years * 7 load forecast errors * 10 reserve margin levels = 2590 total cases. For each of these cases, 400 iterations of unit outage draws are performed which means over one million yearly simulations were completed for the analysis. From this analysis, expected reliability costs can be calculated and compared to the cost of adding additional reserves.

A. Case Probabilities

An example of probabilities given for each case is shown in Table 13. It is assumed that each weather year is given equal probability and each weather year is multiplied by the probability of each load forecast error point to calculate the case probability.

Table 13. Case Probability Example

Weather Year	Weather Year Probabilitiy	Load Forecast Error	Load Forecast Error Probability	Total Case Probability (Weather Yr Prob x LFE Prob)
1975	2.70%	-6.23%	1.64%	0.0443%
1975	2.70%	-3.76%	11.29%	0.3051%
1975	2.70%	-1.79%	22.46%	0.6070%
1975	2.70%	0.00%	29.23%	0.7900%
1975	2.70%	1.79%	22.46%	0.6070%
1975	2.70%	3.76%	11.29%	0.3051%
1975	2.70%	6.23%	1.64%	0.0443%
1976	2.70%	-6.23%	1.64%	0.0443%
1976	2.70%	-3.76%	11.29%	0.3051%
1976	2.70%	-1.79%	22.46%	0.6070%
1976	2.70%	0.00%	29.23%	0.7900%
1976	2.70%	1.79%	22.46%	0.6070%
1976	2.70%	3.76%	11.29%	0.3051%
1976	2.70%	6.23%	1.64%	0.0443%

For this study, reliability costs are defined as the following:

1) Carrying Cost of Reserves + Production costs above that of a CT + Imports above the cost of a CT + Expected Unserved Energy Costs - Sales above that of a CT

These components are calculated for each of the above cases and weighted based on probability to calculate an expected reliability cost for the year.

B. Reserve Margin and Capacity Margin Definition

For this study, reserve margin is defined as the following:

- Reserve Margin = (Resources – Demand) / Demand
    - Demand is the Average Summer System Peak Load and has not been reduced by Demand Response
    - Resources are defined based on summer ratings and include Demand Response
    - The solar capacity within the study was given a 50% capacity credit while wind was given a 15% capacity credit (consistent with the 2011 IRP)

VI. Base Case Results

A. Physical Reliability Results

From a physical reliability standpoint, Figure 15 shows LOLE in events per year and LOLH in hours per year for the base case. The one day in 10 year standard (LOLE = 0.1 events per year) falls at a 14.5% summer reserve margin and the LOLH is approximately 0.30 hours per year for that level of reserves. Figure 16 displays expected unserved energy (EUE) at varying levels of reserves. At the 14.5% reserve margin level, EUE is 170 MWh. As demonstrated in the additional sensitivities, physical reliability metrics are sensitive to input assumptions such as weather diversity, transmission availability, neighbor reserve levels, and emergency hydro assumptions.

Figure 15. Base Case LOLE and LOLH

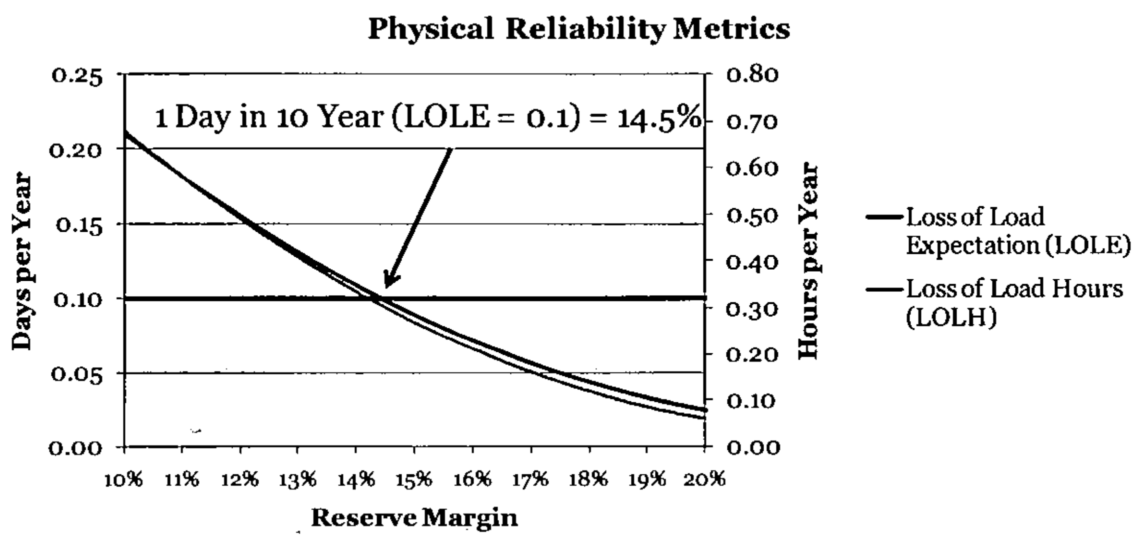
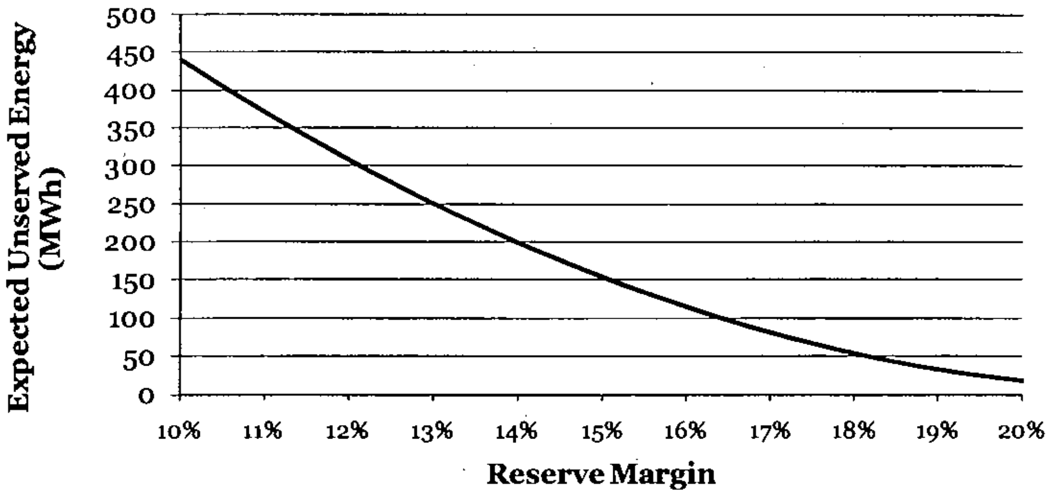


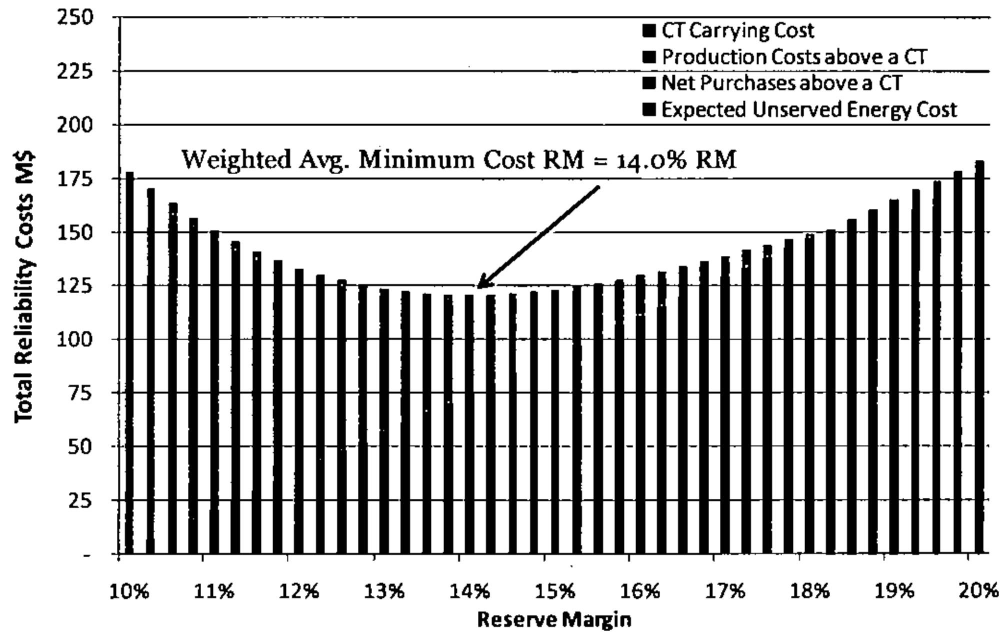
Figure 16. EUE



B. Economic Results

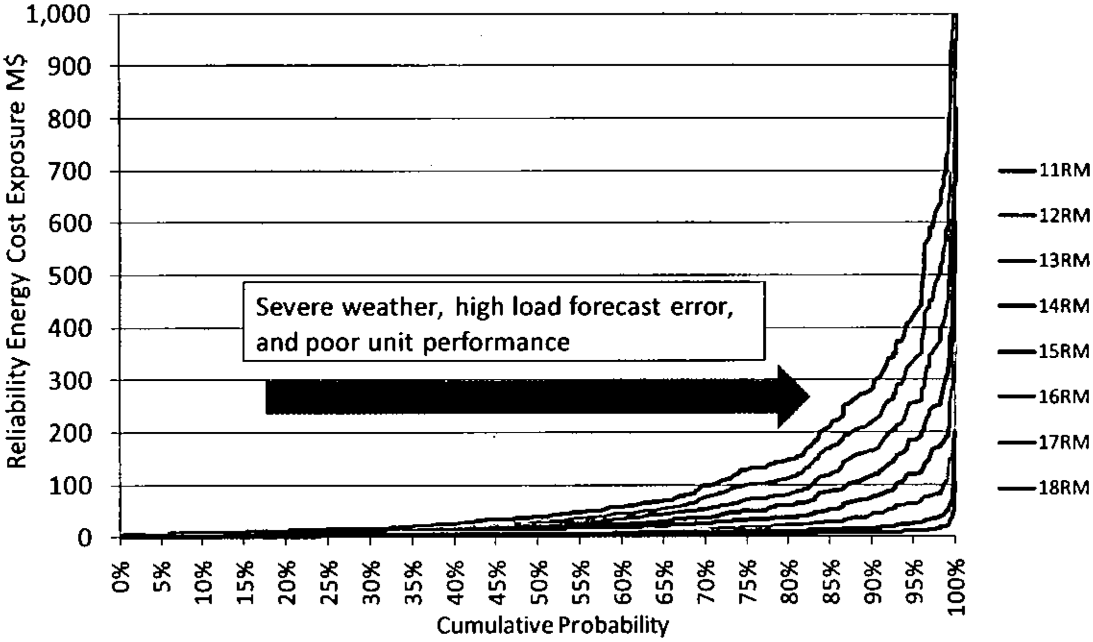
As previously discussed, physical reliability metrics only provide guidance for meeting a few peak load hours over a multi-year study period, and are therefore difficult to calibrate. To supplement the information provided by the base case LOLE analysis, economic reliability metrics were taken into consideration. Economic reliability costs include all costs from the next highest cost resource after a marginal CT all the way to the economic impact of shedding firm load. Since additional capacity will have some benefits in every year, this type of analysis is easily calibrated to actual practice and then allows accurate extrapolation to extreme scenarios. The base case economic results are shown in Figure 17. Based on these results, the long-term minimum cost reserve margin based on the weighted average of all results is 14%. As reserve margin increases, reliability energy costs (Production cost above a CT, net reliability imports above a CT, and cost of unserved energy) decrease while CT carrying cost increases. The flatness of the curve between 14% and 16% should be noted. Since resource additions are too large to perfectly target a reserve margin, some years will inevitably result in reserve margins that are higher than the average economic optimum. The expected financial impact of these additions to the total system cost is not substantial, since the capacity above the weighted average target also brings some financial benefit. For example, the annual expected difference in cost between the 14% reserve margin and 16% reserve margin is only $9 million and the higher level of reserves may provide risk benefits.

Figure 17. Base Case Weighted Average Economic Reserve Margin



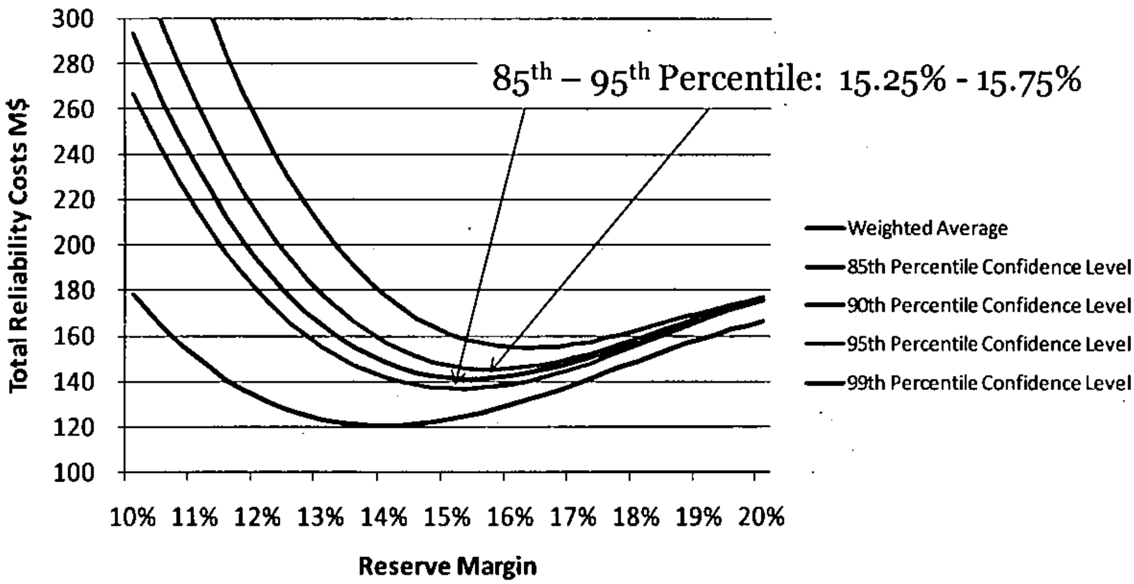
The previous figure represents the weighted average cost exposure and does not illustrate the high cost outcomes that can occur at each reserve margin level. While CT costs are mostly fixed, reliability energy costs are volatile dependent on the weather, load forecast error, or unit performance in a given year, so other confidence levels should be reviewed. While over a 30 year period this may be the optimal reserve margin, any single year can have significant risk at a 14% reserve margin level. Figure 18 shows the reliability energy costs on a probability weighted basis. At a 14% reserve margin, there is a 5% chance that reliability energy costs could exceed $185 million in any given year and a 1% chance that it could exceed $303 million.

Figure 18. Base Case Reliability Cost Exposure Distribution



Next we examined the optimal economic reserve margin recognizing the different risk profile of energy costs and capacity costs. By comparing capacity costs to reliability energy costs during years with extreme weather or poor unit performance as seen in Figure 18, we assessed the tail benefit of additional capacity. The reliability energy costs seen in Figure 18 were taken at different confidence levels (85%, 90%, 95%, and 99% probabilities) and added to the fixed capacity costs at each reserve margin to form the confidence level curves in Figure 19. This assessment showed that in 10% of all scenarios, Duke Energy would receive an economic benefit by adding efficient natural gas turbines up to a reserve margin of 15.50%. This is shown by the 90% confidence level (probability) curve in Figure 19. As we review the weighted average curve in the same figure we can see that by adding capacity to achieve a 16% reserve margin versus a 14% reserve margin, average annual costs only increase by $9 million, but the additional capacity acts as an insurance product to customers. In fact, 10% of the time customers would see their cost exposure decrease by at least $70 million as seen in Figure 18.

Figure 19. Risk Adjusted Reserve Margins



VII. Sensitivity Analysis

The following sensitivities were performed on the base case to only understand the movement in target reserve margins for both physical and economic metrics.

- Include Emergency Hydro: Allows the full nameplate capacity of the hydro fleet to be dispatched during peak periods.
- No Weather Diversity: All neighbors were given the same load shape as Duke to force all neighbors to peak at the same time.
- 50% ATC: The distributions of ATC were reduced by 50% to understand how transmission was impacting the base case results.
- Island Case: Duke is modeled as an island with no outside assistance.
- +2% Neighbor RM Level: The capacity of all neighbors was increased by a 2% reserve margin.
- +50% System EFOR: The EFOR for all Duke resources was increased by 50%.

- Marginal Resource Cost: +/- 25%: The capacity costs for the marginal resource was varied by +/-25%.
- EUE Cost: The cost of unserved energy was varied from $5,000/MWh to $25,000/MWh.
- 2023 Study Year: The study year was moved from 2016 to 2023. Load growth and generation expansion were included for each region and escalation in all economic factors such as the cost of EUE, scarcity pricing, and fuel prices was included for this sensitivity.

Table 14 shows the results of each sensitivity simulated. It is seen that the 0.1 LOLE reserve margin is more sensitive to key assumptions than the weighted average economic case. As discussed previously, this occurs because LOLE is impacted by only a few hours while economics looks at the broader economic impact of all costs above the costs of a CT.

The results show that LOLE is very sensitive to emergency hydro assumptions, weather diversity, and neighbor assistance while the economic results were more stable. Allowing the emergency hydro to be available during all peak periods decreases the LOLE target RM by 3.25% to 11.25% while the economic results were unchanged. Excluding weather diversity shifted the LOLE target up by 3.75 percentage points and the economic target up by 1 percentage point. Dividing the ATC distributions in half had a 1 percentage point impact on the LOLE target and a 2.5 percentage impact on economic results. The ATC sensitivity impacted transmission availability for every hour and so impacted the economic results more than LOLE. However, this sensitivity still indicates that even if substantial changes were to occur to the transmission system (loss of 50% of hourly available transmission capacity), target reserve margins would not need to shift dramatically. Increasing neighbor reserve levels by 2% shifted the LOLE target down by 3.75 percentage points and the economic target down by 0.75 of a percentage point. The island sensitivity should be seen purely as an academic exercise demonstrating the level of reserves the company would carry if it had no outside assistance. If Duke was a stand- alone utility, then it would need to carry reserves of 23.25%. In studying the year 2023, the target only changed slightly. It is expected that a long term reserve margin study should evaluate an optimal target three to five years in the future and therefore 2023 would need to be reviewed again in the 2018 to 2020 time frame.

Regarding the Economic Sensitivities, the cost of unserved energy had little impact on the overall results since firm load shed events are so rare, however, the cost assumed for the marginal CT resource moved the economic reserve margin by approximately +/- .75 of a percentage point. As the marginal resource cost increases, the economic target decreases.

Table 14. Sensitivities

	Physical	Economics	
	LOLE: 1 in 10 Standard Target RM	Weighted Average Target RM	90% Target RM
Base Case	14.50%	14.00%	15.50%
Include Emergency Hydro	11.25%	14.00%	15.50%
No Weather Diversity	18.25%	15.00%	16.75%
50% ATC	15.50%	16.50%	17.50%
Island Case	23.25%		
+2% Neighbor RM	10.75%	13.25%	15.25%
+50% System EFOR	16.75%	16.25%	17.50%
2023 Study Year	14.25%	14.00%	15.75%
EUE Cost: $25,000/MWh		14.00%	15.75%
EUE Cost: $5,000/MWh		13.75%	15.25%
Marginal Resource Cost: +25%		13.25%	14.75%
Marginal Resource Cost: -25%		14.75%	16.00%

VIII. Conclusions/Recommendations

Astrape recommends that Duke set its absolute minimum reserve margin at the 14.5% LOLE target (LOLE = 0.1) and recommends a target of 15.50% based on the 90% confidence level economic target. Since capacity is added in large blocks to take advantage of economies of scale, the actual reserve margin will often be somewhat higher than the target of 15.5%. As shown in the charts and data above, a reserve margin target in the range of 14.5% to 16% produces similar total customer costs whether at the low end or high end of the range. To accommodate large resource additions such as nuclear, coal, or even larger combined cycle resources, the reserve margin would likely rise above the top end of the reserve margin range. However, the additional production cost and economy of scale benefits provided by such resources would likely justify their addition. Therefore, the recommended target reserve margin of 15.50% with a range of 14.5% to 16% should not be considered absolute as all resource decisions should be made on a case-by-case basis.

The results should be reviewed periodically as there are shifts in generation mix, DSM, intermittent resource penetration, or load shape that could impact results. Provided that the results are greatly impacted by regional reserve margins, it is also recommended that Duke keep a close eye on the surrounding market. Short term capacity decisions should also be reviewed on a case-by-case basis. Since physical capacity changes can rarely be implemented inside a 3-year window, the cost of any procurement should be weighed against the distribution of reliability events and the distribution of reliability costs associated with not purchasing the capacity. Even in cases when Duke is below its minimum target reserve margin, economic and physical reliability metrics may suggest not procuring additional capacity. Or an analysis may suggest purchasing more capacity than is needed to achieve the minimum target.

VIX. Confidential Appendix

A. Hydro Modeling

Hydro Resources (MW)

Unit Name	January	July
ROR	7	2
Scheduled (Peak Shaving)	585	440
Emergency	598	658

Total	1,100	1,100

Unit Name	January	July
SEPA Scheduled (Peak Shaving)	62	62

SEPA Total	62	62

B. Unit Outage Rates

The following table shows the energy weighted and capacity weighted system equivalent forced outage rates (EFOR) of the entire Duke fleet. Energy weighted EFORs are typically lower than capacity weighted EFORs because base load resources tend to have better availability than resources those that are rarely used. The capacity weighted values are more important for a reliability analysis because it is important to understand the availability of resources during peak conditions. Typically, unit performance improves during the peak season because resources are planned to be available during peak conditions.

System EFOR

	Energy Weighted	Capacity Weighted
EFOR including MO	[redacted]	[redacted]
EFOR excluding MO	[redacted]	[redacted]
Peak Season EFOR including MO	[redacted]	[redacted]
Peak Season EFOR excluding MO	[redacted]	[redacted]

Nuclear Resource Forced Outage Rates

Unit Name	EFOR
Catawba 1	[redacted]
Catawba 2	[redacted]
McGuire 1	[redacted]
McGuire 2	[redacted]
Oconee 1	[redacted]
Oconee 2	[redacted]
Oconee 3	[redacted]

Due to the joint ownership arrangements on Catawba 1-2 and McGuire 1-2, Duke is responsible for 108MW of additional load when any of these four nuclear units is on outage. Astrape has handled this by tying the operation of 108 MWs of CT capacity to each of the four units. By modeling these resources in this manner, the 108 MWs of CT capacity will not be available when the nuclear resource is unavailable which approximates a load increase to the system.

Baseload and Intermediate Resource Forced Outage Rates

Unit	Avg Operating Hours	EFOR including MO	EFOR excluding MO	Peak Season EFOR including MO	Peak Season EFOR excluding MO
Allen 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Allen 2					
Allen 3					
Allen 4					
Allen 5					
Belews Creek 1					
Belews Creek 2					
Cliffside 5					
Marshall 1					
Marshall 2					
Marshall 3					
Marshall 4					
Buck CC					

*Buck CC and other DEC CCs will use [redacted] EFOR given the lack of historical CC data

Peaking Resource Forced Outage Rates

Unit	Avg Operating Hours	EFOR including MO	EFOR excluding MO	Peak Season EFOR including MO	Peak Season EFOR excluding MO
Lee 1 NG	[redacted]				
Lee 2 NG	[redacted]				
Lee 3 NG	[redacted]				
Lee CT1	[redacted]				
Lee CT2	[redacted]				
Lincoln CT1	[redacted]				
Lincoln CT2	[redacted]				
Lincoln CT3	[redacted]				
Lincoln CT4	[redacted]				
Lincoln CT5	[redacted]				
Lincoln CT6	[redacted]				
Lincoln CT7	[redacted]				
Lincoln CT8	[redacted]				
Lincoln CT9	[redacted]				
Lincoln CT10	[redacted]				
Lincoln CT11	[redacted]				
Lincoln CT12	[redacted]				
Lincoln CT13	[redacted]				
Lincoln CT14	[redacted]				
Lincoln CT15	[redacted]				
Lincoln CT16	[redacted]				
MillCreek CT1	[redacted]				
MillCreek CT2	[redacted]				
MillCreek CT3	[redacted]				
MillCreek CT4	[redacted]				
MillCreek CT5	[redacted]				
MillCreek CT6	[redacted]				
MillCreek CT7	[redacted]				
MillCreek CT8	[redacted]				
Rockingham CT1	[redacted]				
Rockingham CT2	[redacted]				
Rockingham CT3	[redacted]				
Rockingham CT4	[redacted]				
Rockingham CT5	[redacted]				

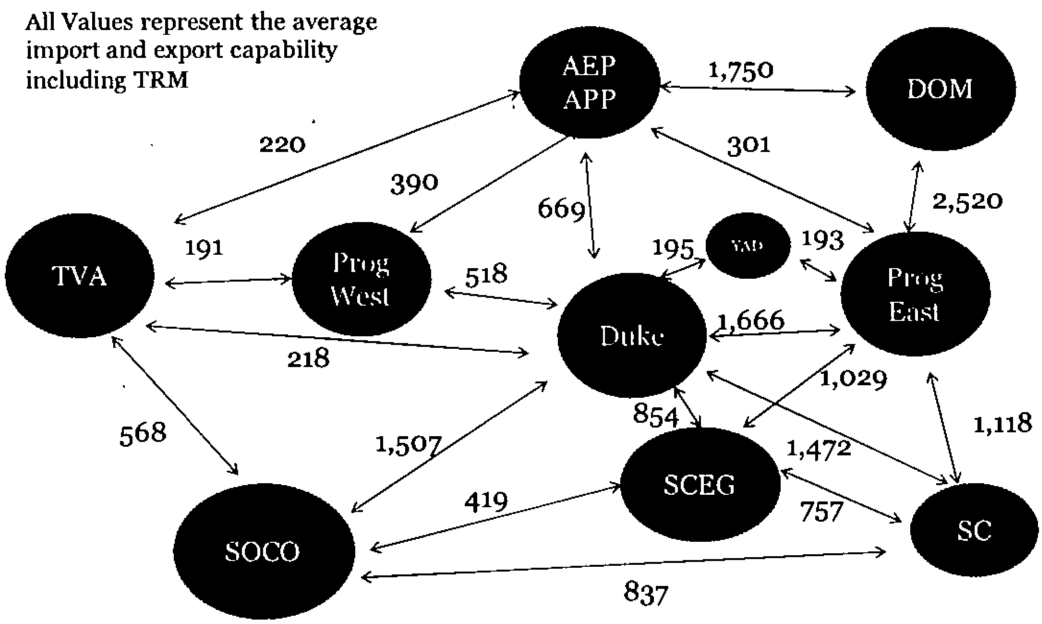
Due to higher regional reserve margins in recent years, the average operating hours of peaking capacity was relatively low. If a unit only runs on average 10 hours a year and has one outage event of 10 hours then the calculated EFOR (repair hours/(repair hours + operating hours)) is 50%. If these peaking resources were needed for several hundred hours it is expected that the EFOR would be much less than 50%. To make this adjustment hours were added to the time to fail distribution which are shown in the following table to represent more reasonable EFOR targets for these units that did not have significant operating histories. Astrape has experienced this issue relative to historical peaking EFORs in all its previous studies and has found that an EFOR between 10% and 20% is a reasonable target for these resources as they are needed more frequently during peak periods.

Peaker EFOR Correction Values

	EFOR Target	Time to Fail Adder
Lincoln CT11	[redacted]	
Lincoln CT13		
Lincoln CT15		
Lincoln CT2		
Lincoln CT7		
MillCreek CT7		
Rockingham CT1		
Rockingham CT2		
Rockingham CT3		
Rockingham CT4		
Rockingham CT5		
Wayne 2		

C. Available Transmission Capability and TRM by Region

Region	ATC IMPORT (MW)		TRM IMPORT (MW)	TOTAL (MW)
Progress_East	min	1,857		
Progress_East	average	4,418	1,835	6,253
Progress_East	max	6,064		
Progress_West	min	400		
Progress_West	average	1,064	198	1,262
Progress_West	max	1,553		
SOCO	min	474		
SOCO	average	3,424	-	
SOCO	max	4,877		
Santee Cooper	min	1,461		
Santee Cooper	average	4,130	372	4,502
Santee Cooper	max	5,855		
AEP	min	2,127		
AEP	average	3,414	-	
AEP	max	3,960		
Dominion	min	1,965		
Dominion	average	3,636	372	4,008
Dominion	max	4,692		
Duke	min	3,035		
Duke	average	6,096	398	6,494
Duke	max	9,443		
SCEG	min	2,072		
SCEG	average	2,874	372	3,246
SCEG	max	3,093		
TVA	min	470		
TVA	average	1,304	-	1,304
TVA	max	1,576		


All Values represent the average import and export capability including TRM
AEP APP
DOM
TVA
Prog West
Duke
Prog East
SCEG
SC
SOCO
1,750
220
390
301
669
2,520
191
518
195
193
1,666
218
1,029
568
1,507
854
1,118
1,472
419
757
837

D. Generic Combustion Turbine Characteristics

Generic Combustion Turbine Characteristics

Capital Cost including transmission upgrades- 2011$/kW	[redacted]	740 MW Summer Rating
Escalation (%)	3%	
Fixed O&M - 2011$/kW-yr	[redacted]	
Escalation (%)	3%	
Capital Cost - 2016$/kW	[redacted]	
Fixed Charge Rate	11.6%	
Life of Plant (years)	30	
Discount Rate	7%	

CT Capacity Costs

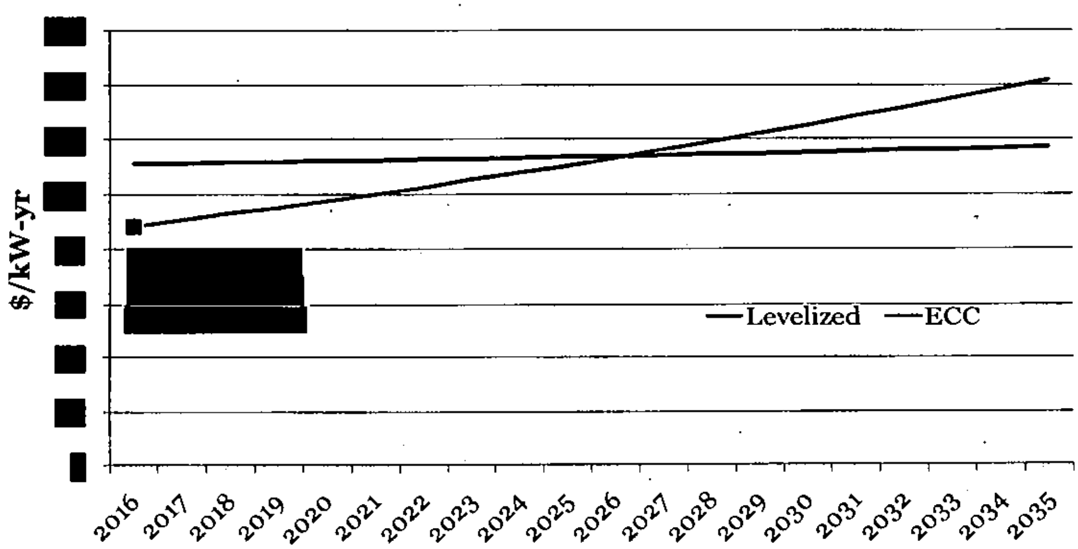


Exhibit No. 2
Docket No. E-100, Sub 137

2012

Progress Energy Carolinas 2012 Generation Reserve Margin Study

Astrape Consulting
8/17/2012

Contents

Executive Summary

The reserve margin study performed by Astrape Consulting was requested by Progress Energy Carolinas in response to North Carolina Utilities Commission Order dated October 26, 2011 in Docket No. E -100, Sub 128. The Order requires PEC to perform a comprehensive reserve margin study and include it as part of its 2012 biennial IRP report.

The optimal planning reserve margin for Progress Energy is based on providing an acceptable level of physical reliability and minimizing economic costs to customers. Customers generally expect power to be available 24 hours a day, 365 days a year, but it is economically unreasonable for a load serving entity to maintain enough reserves to meet this expectation. From a physical reliability perspective, Loss of Load Expectation (LOLE) decreases as reserve margin increases. The most common physical metric used in the industry is to target a system reserve margin that meets the one day in 10 year standard which is interpreted as one firm load shed event every 10 years (LOLE = 0.1). From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. The economic optimum is defined as the point where the cost of additional reserves plus the cost of reliability events on customers is minimized. For this study, the Progress Energy reserve margin is defined as the following:

- Reserve Margin = (Resources – Demand) / Demand
    - Demand is the Summer System Peak Load and has been reduced by Load Management (DSM and Energy Efficiency)
    - Resources are defined based on summer ratings and do not include DSM or Energy Efficiency

Astrape Consulting has taken a stochastic approach in modeling the uncertainty of weather, economic load growth, unit availability, hydro availability, and transmission availability for emergency tie assistance. Utilizing a multi-area reliability model called SERVM (Strategic Energy and Risk

Valuation Model), over 1 million yearly simulations were performed at various reserve margins to calculate the physical reliability metrics and corresponding expected reliability costs. The physical metrics and reliability costs were used to determine an optimal planning reserve margin.

From an economic perspective, the study defines the capacity costs as the annual carrying costs associated with the marginal resource which for this study is a new natural gas combustion turbine. The study defines reliability energy costs as any energy costs the system experiences above the dispatch cost of the marginal resource. These costs include the dispatch of expensive peaking resources such as oil CTs, net imports of expensive market purchases during capacity shortages, and the societal cost of unserved energy.

Summary of Results and Key Insights

The reserve margin that results in 1 day in 10 year LOLE is 14.5% as shown in Figure ES1. As reserve margin increases, loss of load expectation decreases and meets 0.1 LOLE at a 14.5% reserve margin. Loss of load hours (LOLH) approaches 0.24 at the 14.5% reserve margin as shown in Figure ES2.

Figure ES1. LOLE

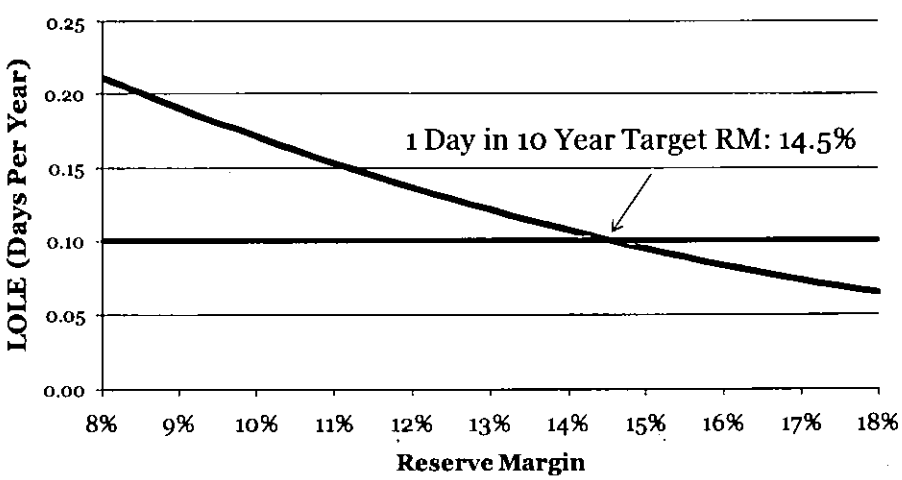
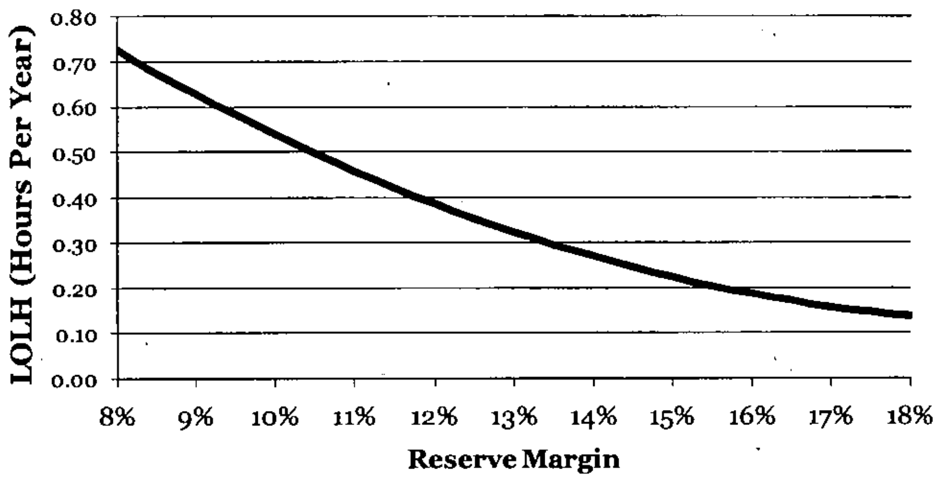


Figure ES2. LOLH



It should be noted that physical metrics are sensitive due to their infrequent nature. Load diversity, transmission availability, coincident unit outages, and neighbor reserve levels can result in a shift of the 0.1 LOLE reserve margin by several percentage points as shown in the sensitivity section of the report. For this reason, we recommend assessing the economics of reliability as well as the physical reliability metrics. This allows planners to not only assess the comprehensive benefits of incremental capacity, but also allows for better calibration of physical reliability metrics.

The economic reliability assessment which balances the costs and benefits of incremental capacity demonstrates that the minimum weighted average cost reserve margin is 15.5% as shown in Figure ES3 which is slightly higher than the 0.1 LOLE reserve margin. As reserve margin increases, the CT carrying costs rise and the reliability energy costs made up of production costs above a CT, net imports above a CT, and expected unserved energy decrease. Between 15% and 17%, the flatness of the curve indicates that there is not a significant cost impact to being slightly above the minimum cost point. Since resource additions are too large to perfectly target a reserve margin, some years will inevitably result in reserve margins that are higher than the average economic optimum. The expected financial impact of these additions is not substantial, since the capacity above the weighted average target also brings some financial benefit. For example, the annual expected difference in cost between the 15% reserve margin and 17% reserve margin is only $2 million and can provide substantial risk benefit.

Figure ES3. Minimum Weighted Average Cost Reserve Margin

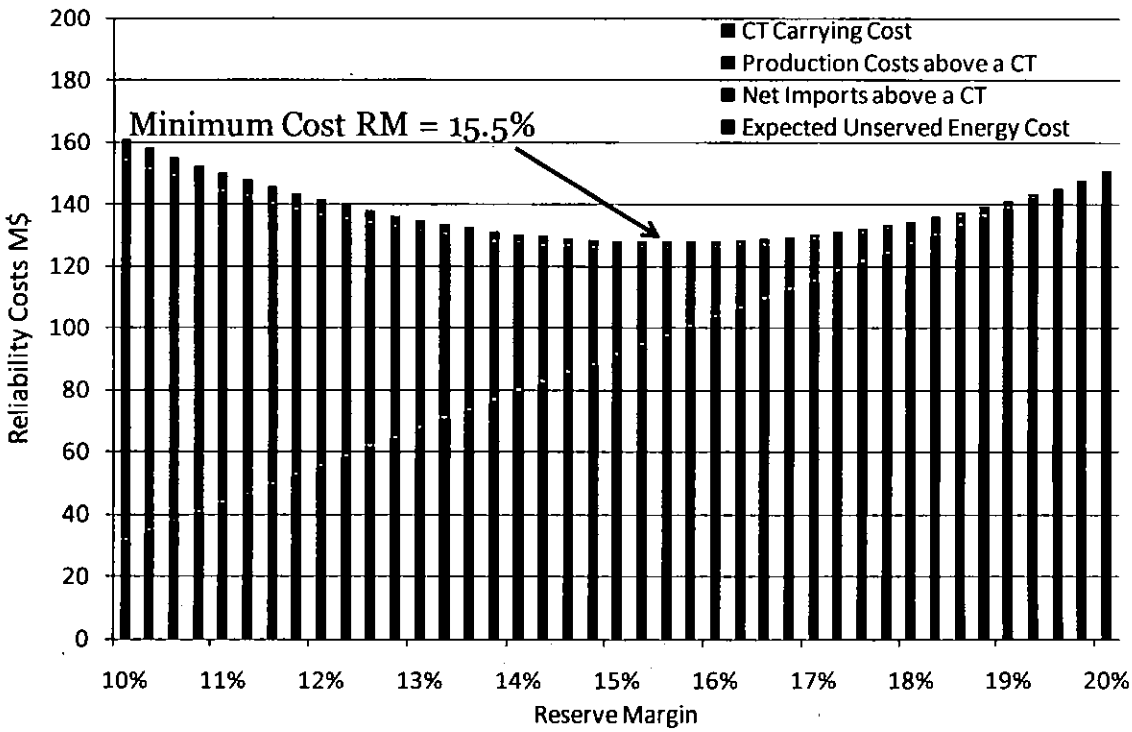
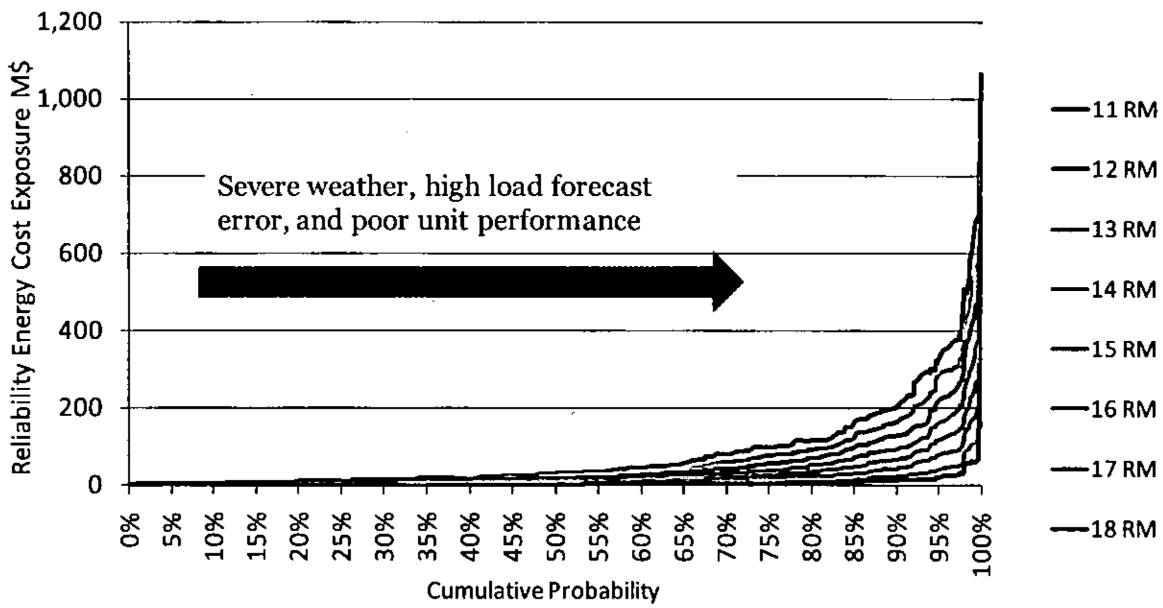


Figure ES4 demonstrates the distribution of reliability energy costs seen in Figure ES3 at each reserve margin level. It should be noted that a physical reliability target of 0.1 LOLE (14.5% RM) still has a potential for high reliability cost years due to abnormal weather, economic growth, or poor unit performance in the region as shown in the figure. At a 15% reserve margin, there is a 5% chance that reliability energy costs could exceed $118 million in any given year and a 1% chance that they could exceed $232 million.

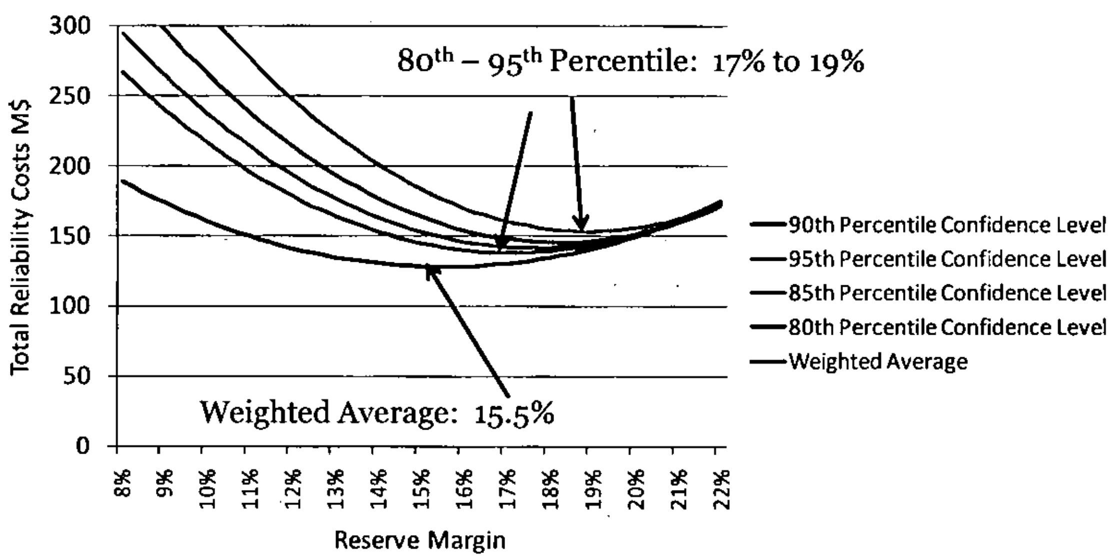
Figure ES4. Distribution of Reliability Energy Costs



Next we examined the optimal economic reserve margin recognizing the different risk profile of energy costs and capacity costs. By comparing capacity costs to reliability energy costs during years with extreme weather or poor unit performance as seen in Figure ES4, we assessed the tail benefit of additional capacity. The reliability energy costs seen in Figure ES4 were taken at different confidence levels (85%, 90%, 95%, and 99% probabilities) and added to the fixed capacity costs at each reserve margin to form the confidence level curves in Figure ES5. This assessment showed that in 10% of all scenarios, Progress Energy would receive an economic benefit by adding efficient natural gas turbines up to a reserve margin of 18.25%. This is shown by the 90% confidence level curve in Figure ES5. As stated previously, when we review the weighted average curve in the same figure we can see that by adding capacity to achieve a 17% reserve margin versus a 15 % reserve margin, average annual costs only increase by $2 million, but the additional capacity acts as an insurance product to customers. In fact, 10% of the time customers would see their cost exposure decrease by at least $42 million in any given year as seen in Figure ES4.

It should be noted that for Progress Energy, the primary benefit driving these high confidence level scenarios is the ability to run the additional efficient natural gas turbines and avoid running existing oil units or purchasing energy at some cost between the gas and oil dispatch cost. However, since the existing oil capacity and demand side management capacity already provide the benefit of avoiding the high impact reliability events such as firm load shed and extreme market purchases, reasonable risk mitigation is achieved at an 80% confidence level, or a 17% reserve margin, compared to a 85-95% confidence level for a system that does not have the same oil resource and demand side management penetration.

Figure ES5. Optimal Reserve Margins over a Range of Confidence Levels



Recommendation

Astrape recommends that Progress set its absolute minimum reserve margin at the 14.5% LOLE target (LOLE = 0.1). Since capacity is added in large blocks to take advantage of economies of scale, the actual reserve margin will often be somewhat higher than the minimum. As shown in the charts and data above, a reserve margin target in the range of 14.5% to 17% produces similar total customer costs whether at the low end or high end of the range. To accommodate large resource additions such as nuclear or coal or even combined cycle, the reserve margin would likely rise above the top end of the reserve margin range at 17%. However, the additional production cost and economy of scale benefits provided by such resources would likely justify their addition. Therefore, the recommended target reserve margin range of 14.5% to 17% should not be considered absolute; resource decisions should be made on a case-by-case basis.

I. List of figures

II. List of tables

III. Input Assumptions

A. Study Year

The selected study year is 2016. The year 2016 was chosen because it is three to four years into the future which is indicative of the amount of time needed to permit and construct a new generating facility. By looking three to four years out, this study reflects a longer term optimal reserve margin. Lower economic load forecast error as well as surrounding market conditions could potentially allow Progress to carry slightly lower reserves in the short term.

Although 2016 was selected for the base case simulations, the SERVM simulation results should also apply for future years beyond 2016 assuming that resource mixes and market structures do not change drastically over that term. To that end, several sensitivities were run to reflect changes in the resource mix and in the market that could occur in this time period as well as a look at the 2023 Study Year.

B. Load Modeling

Table 1. 2016 Load Forecast

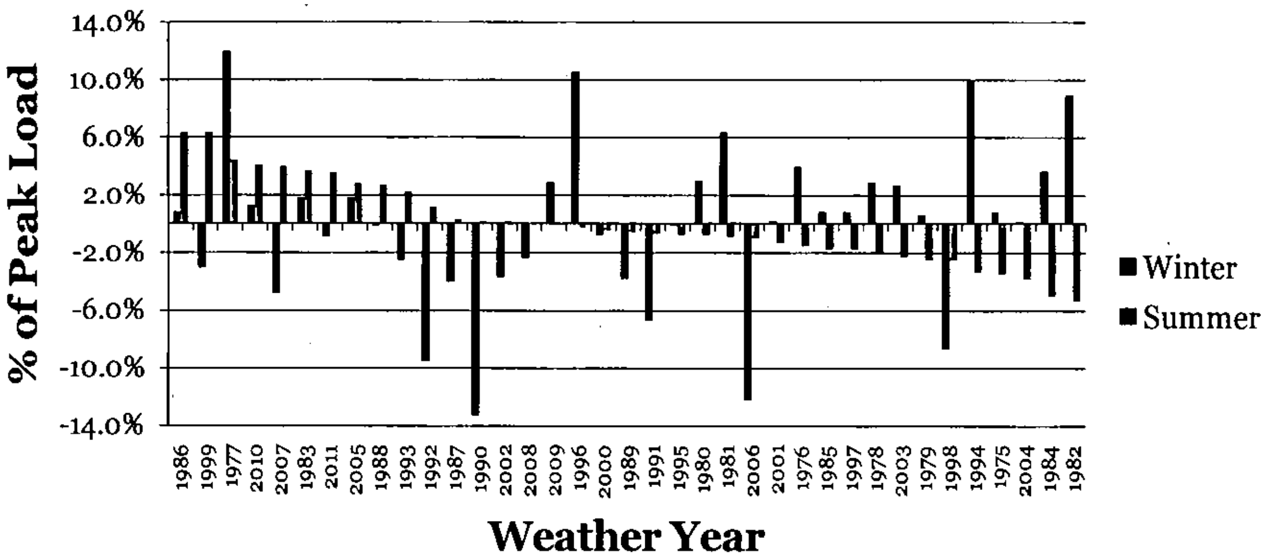
	East	West
Winter Non-Coincidental Peak (MW)	12,115	1,108
Summer Non-Coincidental Peak (MW)	12,897	986
Combined Coincidental Summer Peak (MW)	13,835	
Combined Coincidental Winter Peak (MW)	13,154	
Annual Energy (MWh)	64,040,184	5,263,612

Table 1 displays the non-coincidental peak and energy forecasts for 2016 under normal weather conditions for both the East and West regions. The East is expected to have a winter peak of 12,115 MW and a summer peak of 12,897 MW. The West is expected to have a winter peak of 1,108 MW and a summer peak of 986 MW. All values include the reduction for energy efficiency but exclude any other DSM or voltage control reductions.

To model the effects of weather uncertainty, 37 historical weather years were developed to reflect the impact of weather on load. A neural network program was used to develop relationships between weather observations and load based on the last five years of historical weather and load. Different relationships were built for each month of the year using hourly temperature, time of day, day of week, 8 hour prior temperature, 24 hour prior temperature, 48 hour prior temperature, and heating and cooling degree hours.

These relationships were then applied to the last 37 years of weather to develop 37 load shapes for 2016. Equal probabilities were given to each of the 37 load shapes in the simulation. Figure 1 ranks all weather years by peak summer load for the combined East and West systems. In the most severe weather conditions, the summer peak can be approximately 6% higher than the peak under normal weather conditions and 12% for the winter. The reason for the larger variation in winter loads is primarily due to the larger maximum variation of temperature versus normal weather of 11 to 12 degrees; whereas; in the summer maximum variation versus normal weather is only 5 to 6 degrees.

Figure 1. 2016 Combined Peak Load Variability Vs. Normal Weather



The difference in frequency of high load periods during winter versus summer can be seen in Figure 2. The duration of high load is far less in the winter causing the summer to have higher reliability risk. Capacity resource ratings are also higher in the winter causing the risk of reliability to be less. So despite higher variation in winter peak loads, sustained high loads in the summer cause the majority of reliability events.

Figure 2. Frequency of High Load Hours for Winter and Summer

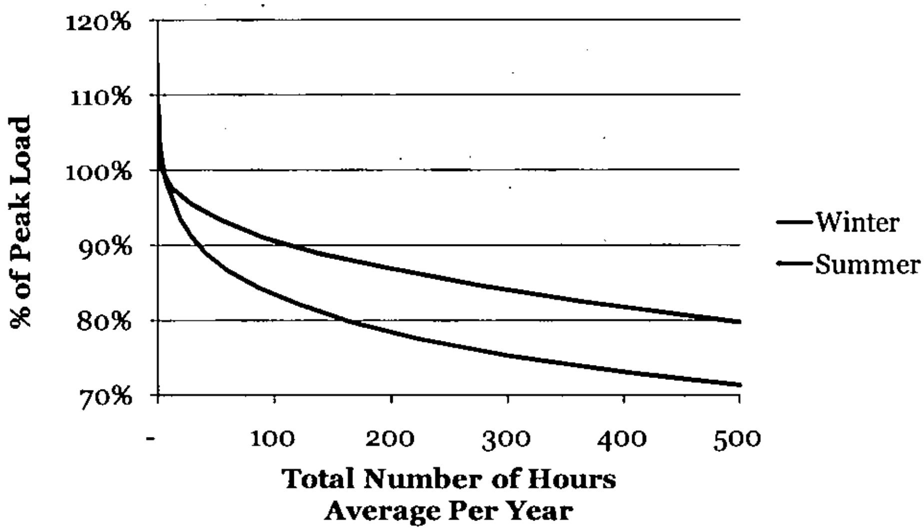


Table 2 summarizes the combined summer and winter peaks by weather year. The table shows that recent years including 2007, 2010, and 2011 were among the most severe summers.

Table 2. 2016 Peak Load Rankings for All Weather Years

Summer Peaks

Max	14,724	6.42%
Forecast	13,835	

Winter Peaks

Max	14,737	12.03%
Forecast	13,154	

Rank	Weather Year	Calculated Peak (MW)	Versus Forecast (%)	Rank	Weather Year	Calculated Peak (MW)	Versus Forecast (%)
1	1986	14,724	6.4%	1	1977	14,737	12.0%
2	1999	14,712	6.3%	2	1996	14,549	10.6%
3	1977	14,453	4.5%	3	1994	14,477	10.1%
4	2010	14,402	4.1%	4	1982	14,332	9.0%
5	2007	14,382	4.0%	5	1981	13,989	6.3%
6	1983	14,343	3.7%	6	1976	13,678	4.0%
7	2011	14,331	3.6%	7	1984	13,640	3.7%
8	2005	14,223	2.8%	8	1980	13,548	3.0%
9	1988	14,202	2.7%	9	1978	13,543	3.0%
10	1993	14,143	2.2%	10	2009	13,533	2.9%
11	1992	14,005	1.2%	11	2003	13,512	2.7%
12	1987	13,875	0.3%	12	2005	13,396	1.8%
13	1990	13,869	0.2%	13	1983	13,387	1.8%
14	2002	13,859	0.2%	14	2010	13,322	1.3%
15	2008	13,840	0.0%	15	1986	13,272	0.9%
16	2009	13,836	0.0%	16	1997	13,271	0.9%
17	1996	13,802	-0.2%	17	1975	13,270	0.9%
18	2000	13,771	-0.5%	18	1985	13,261	0.8%
19	1989	13,758	-0.6%	19	1979	13,241	0.7%
20	1991	13,742	-0.7%	20	2004	13,180	0.2%
21	1995	13,729	-0.8%	21	2001	13,176	0.2%
22	1980	13,722	-0.8%	22	1995	13,153	0.0%
23	1981	13,713	-0.9%	23	1988	13,142	-0.1%
24	2006	13,701	-1.0%	24	2000	13,058	-0.7%
25	2001	13,648	-1.4%	25	2011	13,035	-0.9%
26	1976	13,623	-1.5%	26	2008	12,833	-2.4%
27	1985	13,600	-1.7%	27	1993	12,828	-2.5%
28	1997	13,590	-1.8%	28	1999	12,747	-3.1%
29	1978	13,554	-2.0%	29	2002	12,663	-3.7%
30	2003	13,520	-2.3%	30	1989	12,646	-3.9%
31	1979	13,492	-2.5%	31	1987	12,619	-4.1%
32	1998	13,487	-2.5%	32	2007	12,525	-4.8%
33	1994	13,362	-3.4%	33	1991	12,275	-6.7%
34	1975	13,359	-3.4%	34	1998	12,019	-8.6%
35	2004	13,308	-3.8%	35	1992	11,905	-9.5%
36	1984	13,138	-5.0%	36	2006	11,545	-12.2%
37	1982	13,094	-5.4%	37	1990	11,395	-13.4%

From an annual energy perspective, the following table shows the top 10 highest weather years. Table 3 shows that 2010 had energy consumption 5.4% higher than normal, as both winter and summer seasons were severe. The second highest weather year reflected only 2.6% higher than average energy consumption.

Table 3. Weather Years Ranked by Total Energy

Annual Energy
Top 10

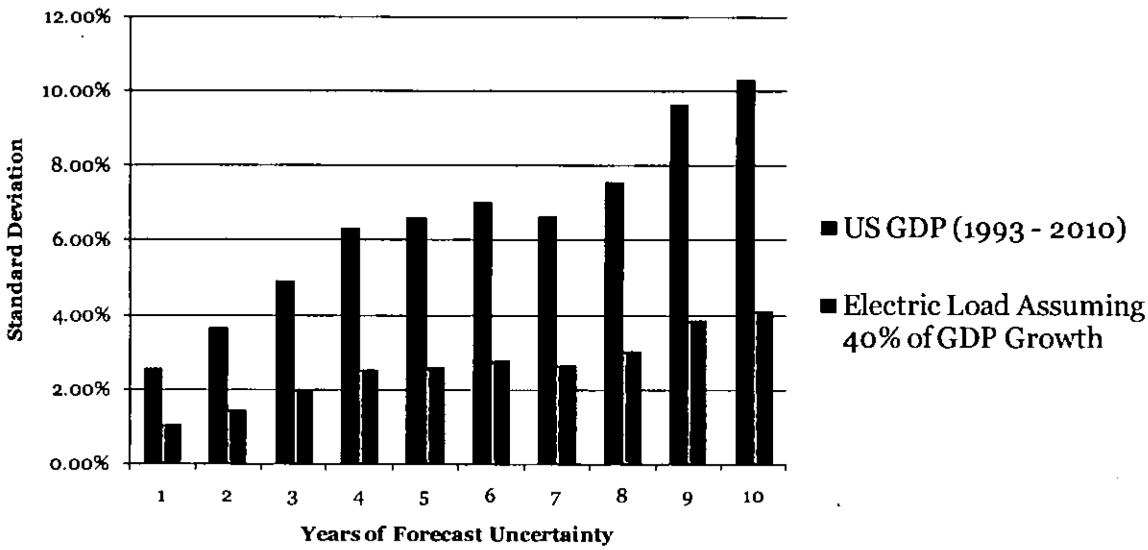
Max	72,280,697	5.4%
Forecast	68,583,317	

Rank	Weather Year	Calculated Energy (MWh)	Versus Forecast (%)
1	2010	72,280,697	5.4%
2	1980	70,375,008	2.6%
3	1977	70,289,930	2.5%
4	2011	69,733,851	1.7%
5	1993	69,698,790	1.6%
6	1978	69,695,880	1.6%
7	2005	69,452,749	1.3%
8	2002	69,264,410	1.0%
9	1986	69,174,020	0.9%
10	1981	69,171,308	0.9%

C. Load Forecast Error

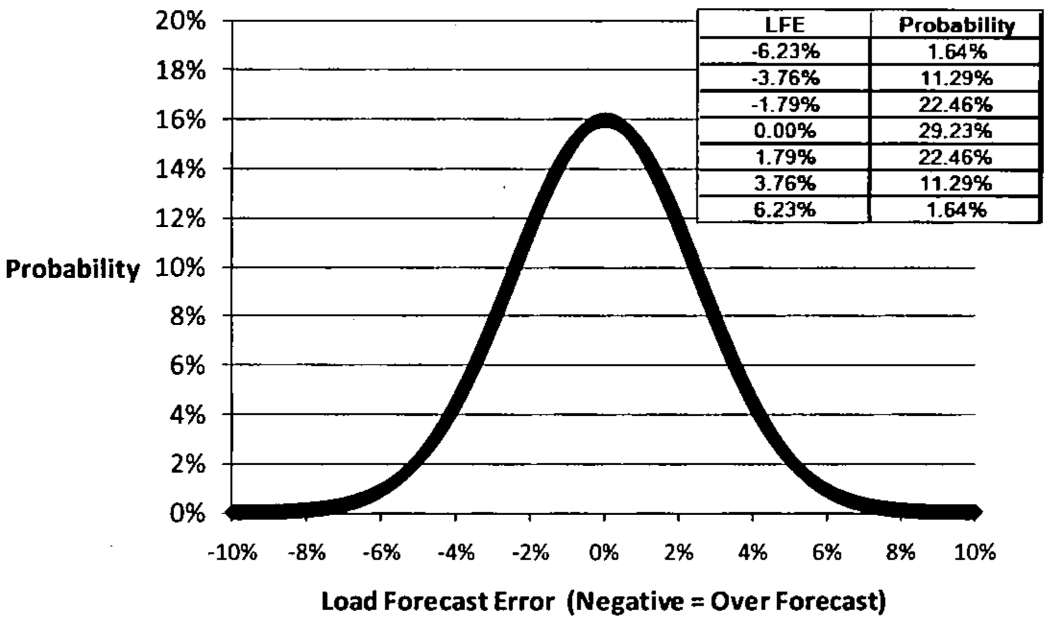
An analysis was performed using the historical Congressional Budget Office four year prior forecasts of GDP and comparing those forecasts to actual data from 1993 – 2010. Comparing how well GDP was predicted four years in advance provides insight into the economic uncertainty that should be applied to utility loads. The chart below shows the standard deviation of historical GDP forecast error for forecasting one to ten years in advance. As expected, the standard deviation of forecast error increases as the number of years increase. Based on discussions with Progress, electric load is assumed to grow at about 40% of GDP. Assuming four year forecast error due to typical construction lead times, standard deviation for load forecast error uncertainty for utility load is 2.5% as shown in the following figure. If lead times for new generation changed substantially, then the standard deviation used to develop the economic load forecast error would need to be adjusted accordingly. However, it is unlikely that typical generation resources can be installed and brought in-service in less than three to four years given the time needed for environmental and regulatory approvals, construction, and startup testing.

Figure 3. Standard Deviation of GDP forecast error (1 to 10 Year Projections)



Astrape also performed a comparison of the company's historical four year prior forecasts to actual weather normalized load. Astrape observed that in recent years there was a tendency to over forecast, as did the industry in general, during the economic downturn seen in the last decade. However, the standard deviation of load forecast error was 2.68%, confirming the 2.5% value seen in the CBO analysis as reasonable. Astrape developed a normal distribution assuming the 2.5% standard deviation as shown in the following Figure 4. The continuous distribution was converted into a discrete distribution with the 7 points shown for use in determining discrete scenarios to be modeled. As an example of how to interpret the economic uncertainty data, there is a 1.64% chance that load will be 6.23% greater than forecasted.

Figure 4. Load Forecast Error



LFE	Probability
-6.23%	1.64%
-3.76%	11.29%
-1.79%	22.46%
0.00%	29.23%
1.79%	22.46%
3.76%	11.29%
6.23%	1.64%

SERVM utilized each of the 37 weather years and applied each of these seven load forecast error points to create 259 different load scenarios.

D. Resources

The resources and seasonal capacities for the 2016 study are shown in the following tables.

Table 4. Nuclear Resource Capacities (MW)

Region	Unit Name	January	July
East	Brunswick 1	965	938
East	Brunswick 2	953	920
East	Harris 1	992	956
East	Robinson 2	783	749
	Totals	3,693	3,563

Table 5. Baseload and Intermediate Resource Capacities (MW)

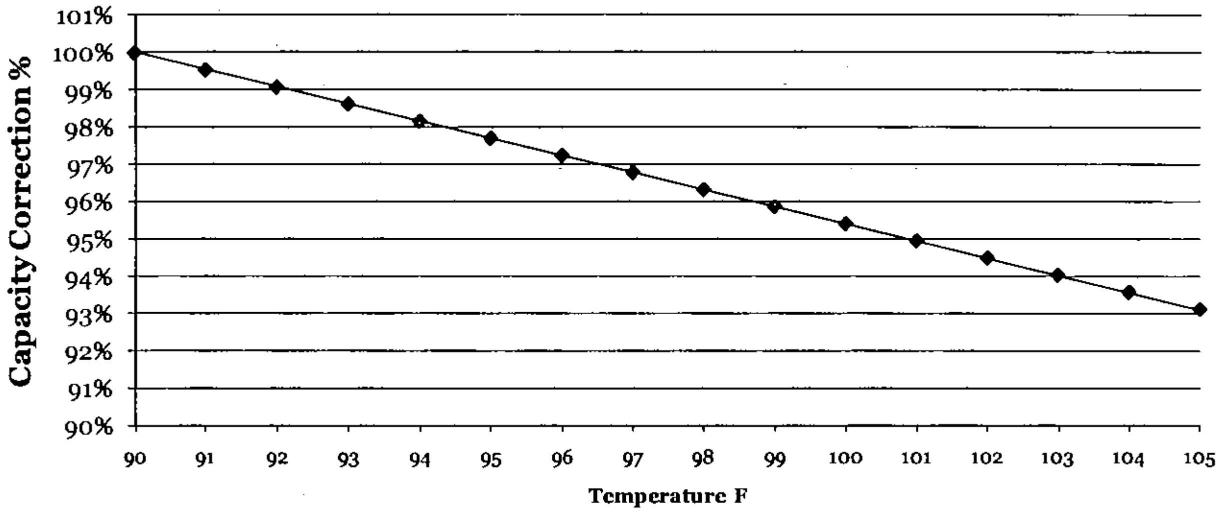
Region	Unit Name	January	July
East	Mayo 1	735	727
East	Robinson 1	179	177
East	Roxboro 1	374	364
East	Roxboro 2	667	662
East	Roxboro 3	698	693
East	Roxboro 4	711	698
East	Richmond CC4	562	490
East	Richmond CC5	708	652
East	Sutton CC	656	554
East	Sutton CC DF	61	71
East	Wayne CC	980	826
East	Wayne CC DF	69	94
East	Butler Warner CC Purchase	260	220
East	Cogen_Stone_Container	20	20
West	Asheville 1	196	191
West	Asheville 2	187	185
West	SOCO CC Purchase	145	145
	Totals	7,208	6,769

Table 6. Peaking Resource Capacities (MW)

Region	Unit Name	January	July	Region	Unit Name	January	July
East	Blewett 1	17	13	East	Richmond 1	178	162
East	Blewett 2	17	13	East	Richmond 2	183	167
East	Blewett 3	18	13	East	Richmond 3	185	169
East	Blewett 4	18	13	East	Richmond 4	186	163
East	Cape Fear 1A	14	11	East	Richmond 6	187	159
East	Cape Fear 1B	13	11	East	Robinson 1CT	15	11
East	Cape Fear 2A	14	11	East	Sutton 1CT	12	11
East	Cape Fear 2B	13	11	East	Sutton 2A	31	24
East	Darlington 1	65	52	East	Sutton 2B	31	26
East	Darlington 10	67	52	East	Wayne 1	192	177
East	Darlington 11	67	52	East	Wayne 2	192	174
East	Darlington 12	120	118	East	Wayne 3	193	173
East	Darlington 13	128	116	East	Wayne 4	191	170
East	Darlington 2	67	52	East	Wayne 5	197	169
East	Darlington 3	51	52	East	Weatherspoon 1	41	33
East	Darlington 4	66	52	East	Weatherspoon 2	41	32
East	Darlington 5	66	52	East	Weatherspoon 3	41	34
East	Darlington 6	67	51	East	Weatherspoon 4	41	32
East	Darlington 7	67	52	East	Broad River 1-3 Purchase	497	482
East	Darlington 8	66	49	East	Broad River 5-5 Purchase	383	331
East	Darlington 9	59	52	East	Anson CT Purchase	357	329
East	Lee 1CT	15	12	West	Asheville 3	178	164
East	Lee 2CT	27	21	West	Asheville 4	185	160
East	Lee 3CT	27	21	West	West CT1	49	42
East	Lee 4CT	27	21	West	West CT2	49	42
East	Morehead 1	15	12	West	West CT3	49	42
					Totals	4,928	4,337

All summer ratings in the previous tables are based on 90 degree F. On an hourly basis, SERVM can adjust the capacity of each resource based on the historical hourly temperature for the weather year being modeled. Because the maximum output of peaking units degrades as temperatures increase, the derating multipliers in Figure 5 were utilized to derate the units above 90 F. These multipliers were developed based on the correction curves of the individual CTs within the Progress fleet and equates to a degradation of 0.46% of capacity per degree F. This ensures correlation of capacity output with load since both are highly dependent on the hourly temperature.

Figure 5. Summer Rating Capacity Multipliers



The hydro portfolio is modeled in segments that include Run of River (ROR), Scheduled (Peak Shaving), and Emergency Capacity. The Run of River segment is dispatched as base load capacity providing its designated capacity every hour of the year. The scheduled hydro is used for shaving the daily peak load but also includes minimum flow requirements. The emergency capacity is used only to prevent firm load shed and the model allows the emergency mode to borrow energy from future dispatch of the scheduled hydro portion with the constraint that the emergency energy amount is enough for only a few hours. Typically hydro resources are not able to be dispatched at their nameplate capacity during peak hours due to water constraints or river flow requirements. By modeling the hydro resources in these three segments, the model captures the appropriate amount of capacity dispatched during peak periods. See the confidential Appendix for the details regarding hydro capacities.

Figure 6 shows the total breakdown of scheduled versus emergency hydro based on the last 37 years of weather. Out of the total 226 MW of capacity owned by the company, only 160 MW on average are available during peak periods. During drought years, less than 100 MW are available on peak in specific months.

Figure 6. Scheduled Capacity versus Emergency Capacity

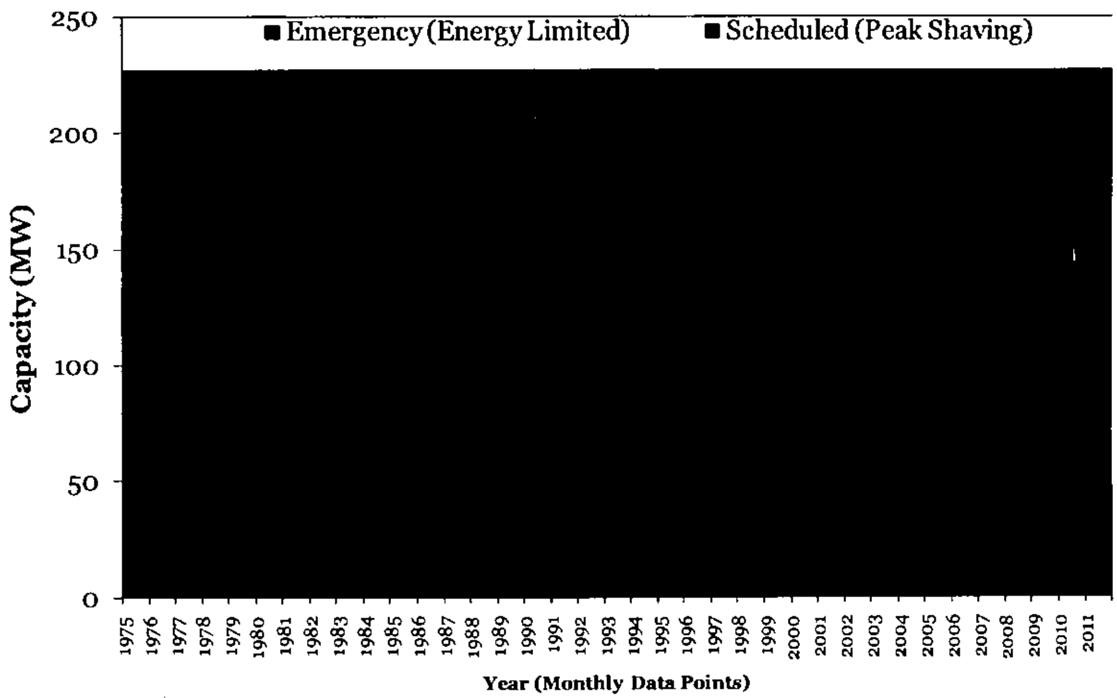


Figure 7 demonstrates the variation of hydro energy by weather year which is input into the model. The drought shown in 2001, 2007, and 2008 is captured in the reliability model.

Figure 7. Hydro Energy by Weather Year

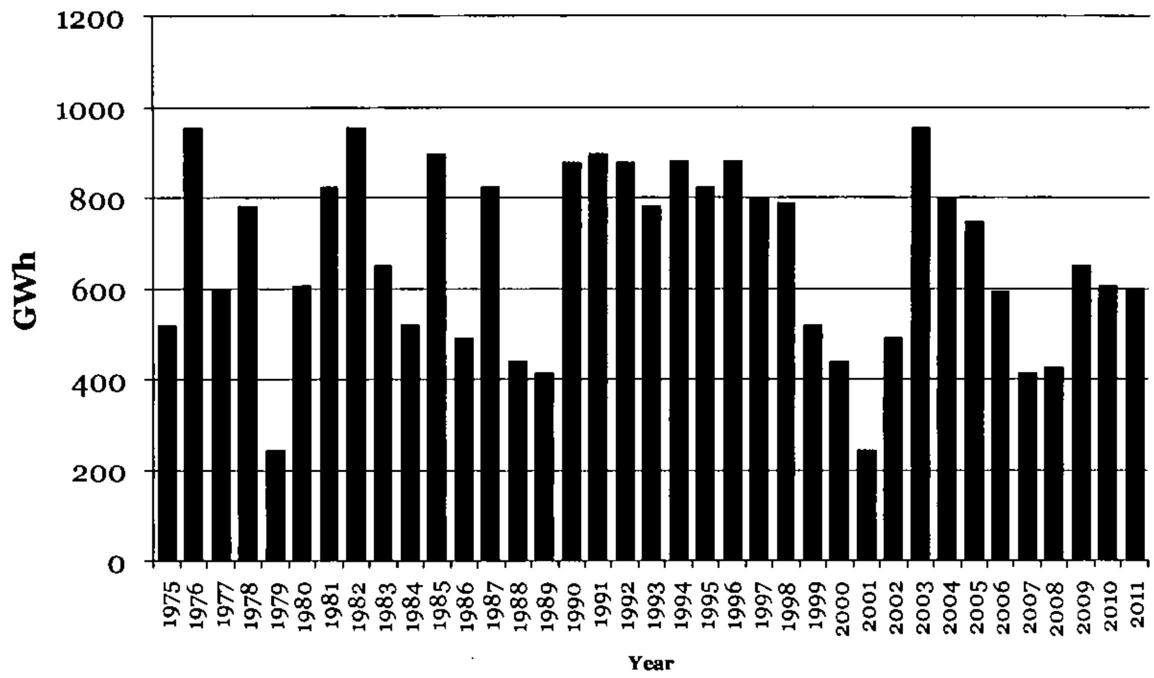


Figure 8 compares actual history of the dispatch level of the hydro resources for a given year as a percentage of time versus how the model dispatches the resources. It is seen that overall, the model is capturing a realistic dispatch of the hydro resources.

Figure 8. Hydro Dispatch Calibration: Percent of Time above Capacity Threshold

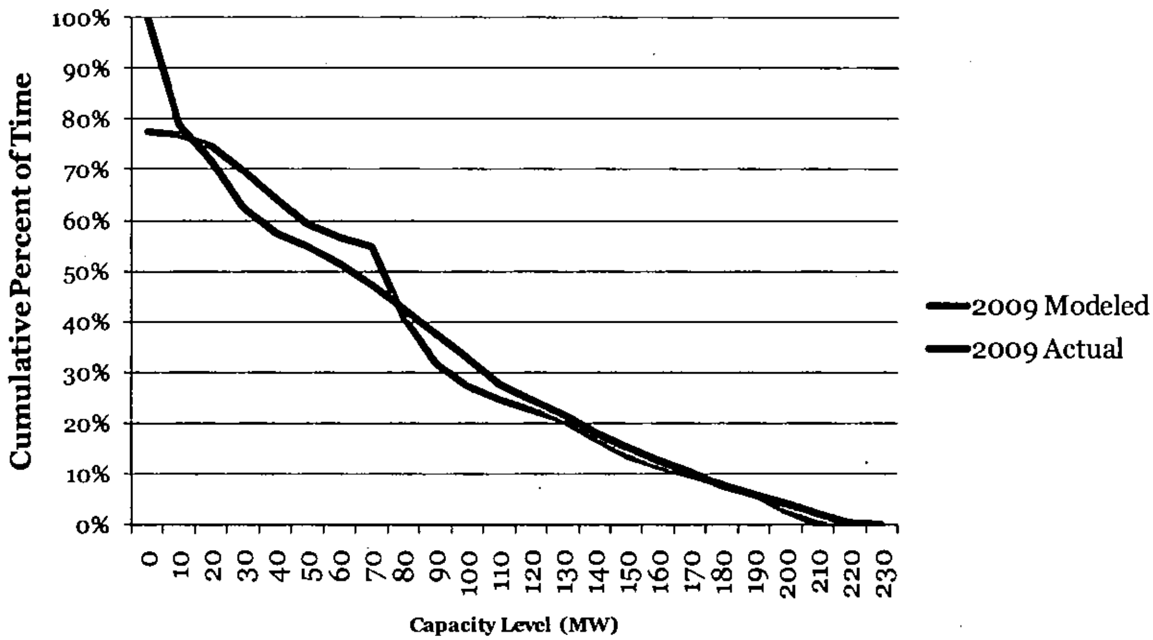


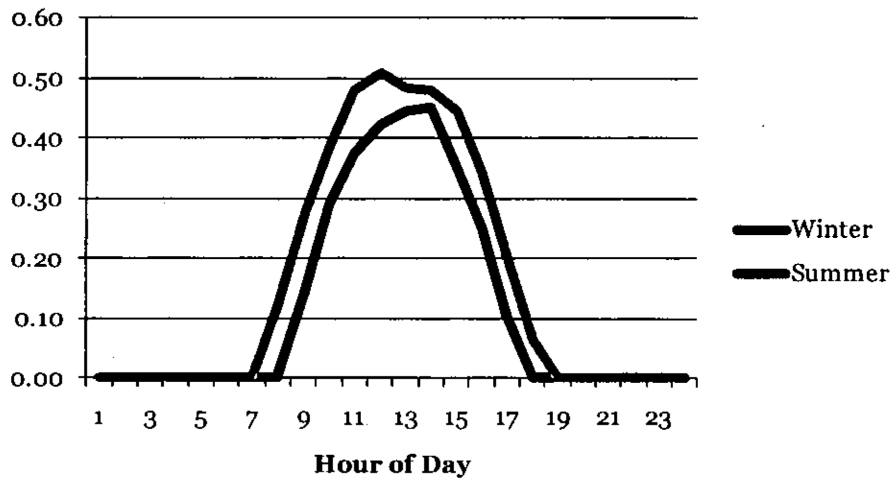
Table 7. Renewable Resources (MW)

Region	Unit Name	January	July
East	Base_Load_7_24_Renewable	107	107
East	Base_Load_5_24_Renewable	134	134
East	Progress_Solar	54	54
East	Progress_Wind	0	0

Totals	295	295

For solar resources, an 8760 hourly generation shape was used. The average summer and winter shape is shown in Figure 9. For each day, SERVM draws a daily shape from all the days in the month. Because historical data is unavailable, this random draw is used for all weather years.

Figure 9. Solar Profile



E. Unit Outage Data

Unlike typical production cost models, SERVM does not use an EFOR for each unit as an input. Instead, historical GADS data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. For this RM Study, 2007-2011 GADS events were entered into SERVM. The events are entered using the following variables:

Full Outage Modeling
Time-to-Repair Hours
Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

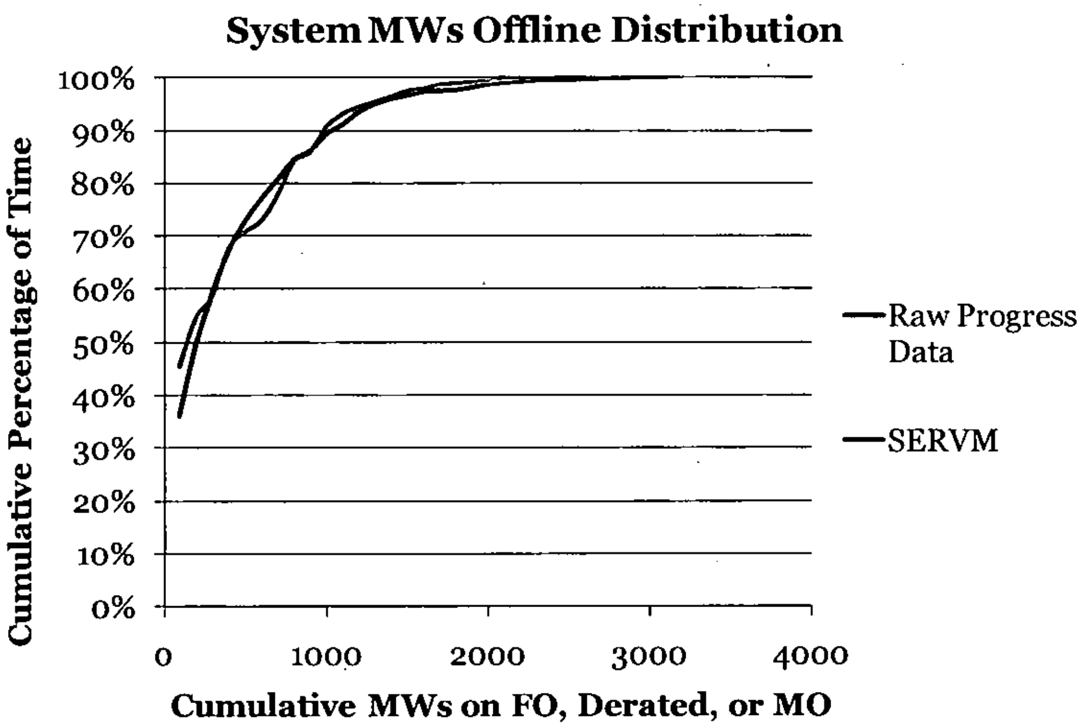
Maintenance Outages
Maintenance Outage Percentage - % of full outages that are maintenance outages. SERVM uses this percentage and allows units to remain online until the following weekend if they are needed in the short term.

For example purposes, assume that from 2007 – 2011, Mayo 1 had 15 full outage events and 30 partial outage events reported in the GADS data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data along with the other variables listed above. These multiple Time-to-Repair and Time-to-Fail distributions are used by SERVM. Because typically there is an improvement in EFOR across the summer, the data is typically broken up into seasons meaning that there is a set of Time-to-Repair and Time-to-Fail inputs for summer, off peak, and winter based on history. Let's assume Mayo 1 is online in hour 1 of the simulation. SERVM will randomly draw a Time-to-Fail value from the distribution provided for both full outages and partial outages. The unit will run for that amount of time before failing. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture.

Unit Outage Calibration

The critical aspect of unit performance modeling for a reliability study is the cumulative MW offline distribution. Most reliability problems are due to significant coincident outages. Figure 10 shows the distribution of outages for Progress Energy. The model has been calibrated to ensure this distribution is captured. Based on the data in Figure 10, the company may have 1,000 MW of capacity offline in 10% of all the hours. This equates to approximately 7.5% in reserve margin. System and individual outage rates are located in the confidential Appendix of this report.

Figure 10. System Capacity Offline as a Percentage of Time



To capture the impact of planned maintenance, the 2016 maintenance schedule was modeled which removes capacity during the shoulder months of the year. Figure 11 shows that when planned maintenance is assumed in the shoulder months that the resulting load level between winter and shoulder periods is relatively flat.

Figure 11. Daily Peak Load Plus Planned Maintenance Requirement

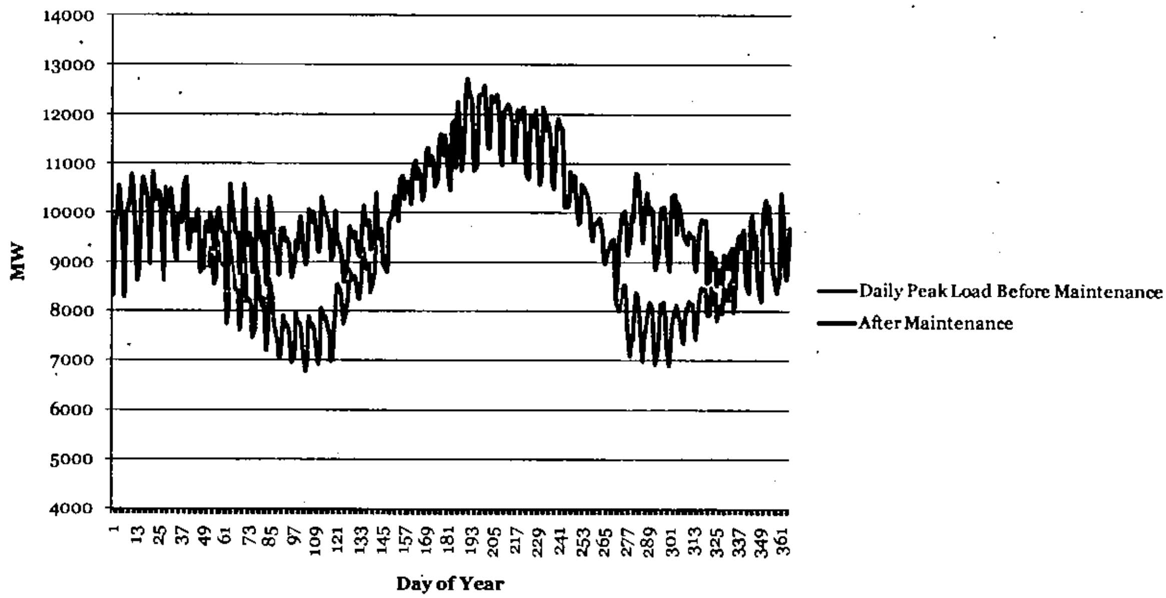
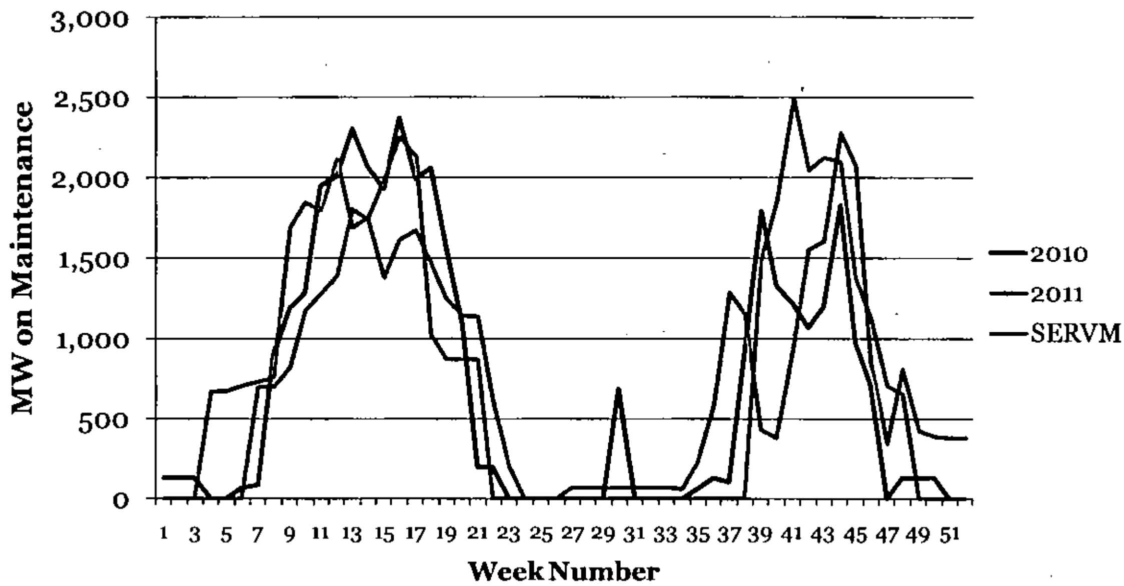


Figure 12 shows the amount of capacity assumed for planned maintenance by week. The graph compares the actual maintenance scheduled for 2010 and 2011 with what was assumed in the SERVM Model.

Figure 12. Average MW on Scheduled Maintenance Per Week



Maintenance schedules were implemented for all neighboring systems during off peak periods based on Progress and Duke current maintenance schedules.

F. Load Management

A total of 1,160 MWs of load management were modeled in the simulation. Energy efficiency (EE) was directly removed from load in the simulation and the remaining resources in the following table were modeled as resources to be called upon given a reliability event. SERVM takes into account the constraints on load management and dispatches accordingly. These constraints include a maximum number of hours per day and hours per year as shown below.

Table 8. Load Management Summary

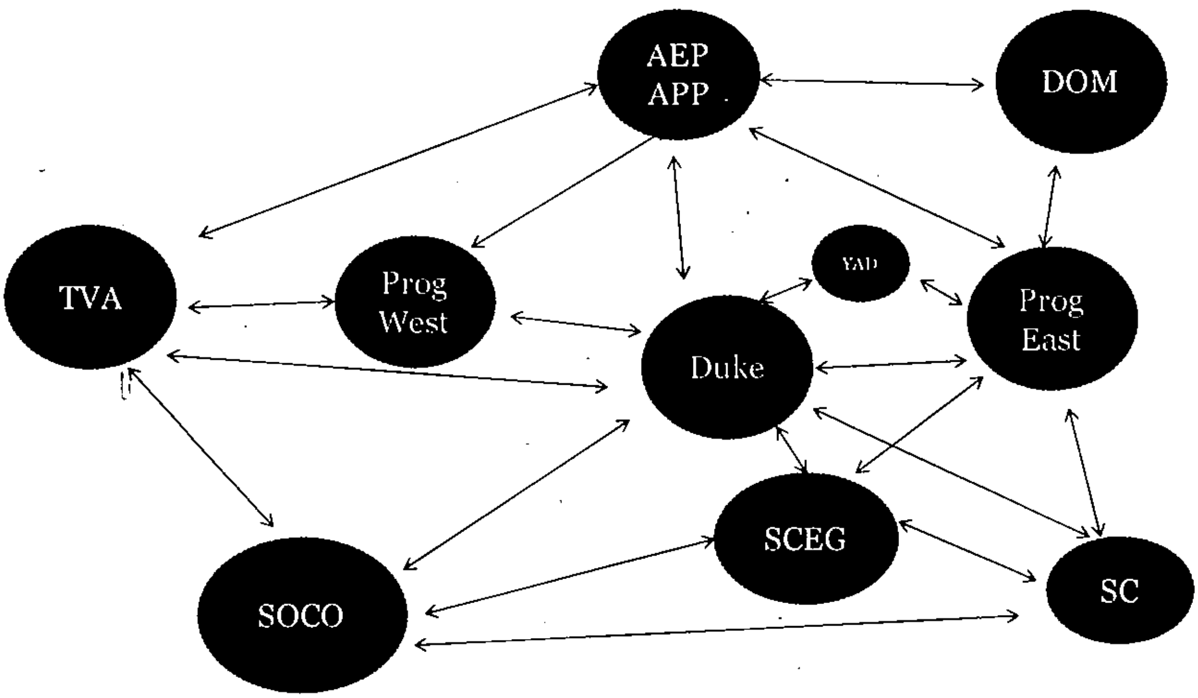
	NC_Curtailable _Load_58	NC_Curtailable _Load_CL	NCRiderD RA	nc-rider-rlc-sum	ncrider-rlc-win	Voltage Control	DSDR	EE (Removed from Load)	Total
Summer (July - 2016) Capacity	256	19	80	232		81	264	211	1144
Hours Per Year	400	400	80	60	60	100	100		
Hours Per Day	8	10	8	4	4	6	6		

G. Multi Area Modeling

The surrounding market must play a significant role in resource adequacy even for a utility the size of Progress Energy Carolinas. If several large generators are offline due to outage during peak season, it is likely that the company would depend on market purchases from surrounding regions.

The market representation used in SERVM was developed through consultation with Progress Energy Staff, EIA forms, Company Integrated Resource Plans (IRP), and reviews of NERC resource adequacy assessments. The base case level of reserves for neighbors is based on target reserve margins for surrounding neighbors. Using this methodology ensures that the company is not leaning on an external market more than is reasonable. Figure 13 shows the topology used for the region.

Figure 13. Regional Topology



Each neighbor's hourly loadshape was modeled based on historical hourly temperature data similarly to the Progress load. By using hourly weather, load diversity was captured for each neighboring area. Diversity of peak load is important to understand especially when examining physical reliability metric results. Table 9 shows the average diversity for summer months across all 37 years for each area within the study. These values represent the percentage reduction from peak load that the neighbor is on average experiencing when Progress Energy is experiencing its peak load. To ensure that Progress Energy was not overstating the expectation of weather diversity and therefore available capacity from neighbors, Astrape believed it was prudent to cap the weather diversity for the East only in any given peak hour at 3% which is shown in the table. This cap on weather diversity is consistent with diversity seen in other studies performed for utilities in the region. A sensitivity assuming no weather diversity was simulated to understand the impact that weather diversity has on lowering the target reserve margin.

Table 9. Neighbor Diversity Factors

	Progress East Perspective	Progress West Perspective
SOCO	1.9%	3.8%
Duke	1.0%	4.6%
AEP	1.7%	5.6%
Dominion	1.3%	5.7%
TVA	1.8%	5.1%
SCEG	1.4%	4.9%
Santee Cooper	1.4%	4.9%
Progress East		5.6%
Progress West	4.2%	

Table 10 displays the capacity and load summary for each of the neighbors modeled near their current target reserve margins. The reserve margin calculations in this table assume that the interruptible capacity is included as a resource. While it is recognized that the region currently contains more capacity than these targets, it is not prudent to expect these additional reserves to be available long term. Outage rates for neighboring units were developed using existing Progress and Duke resources sorted by unit type and capacity size. Hydro resources reflect similar dispatch to the Progress and Duke hydro portfolios.

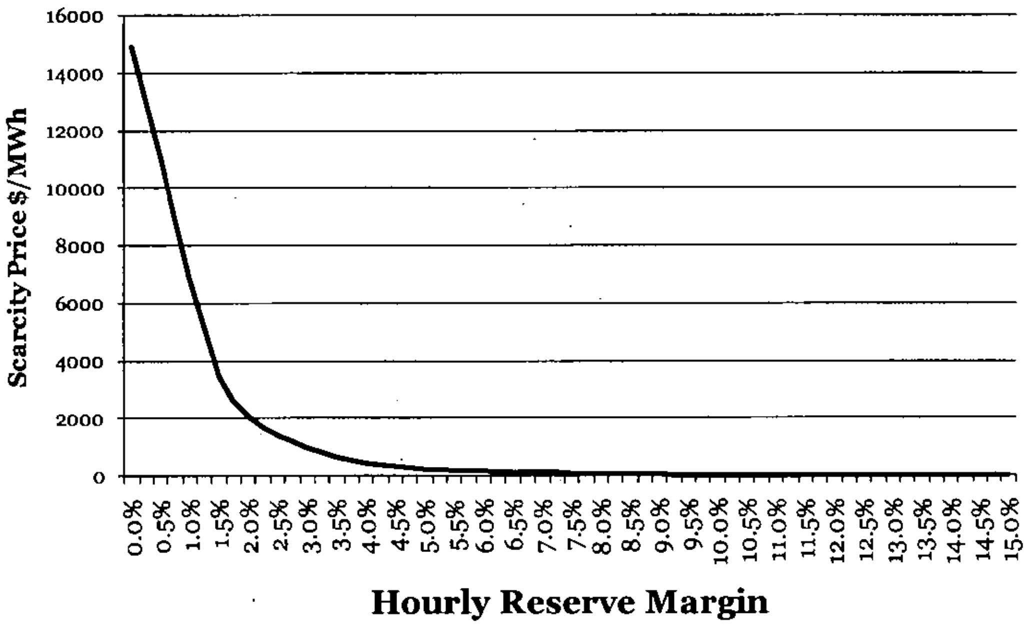
Table 10. Neighbor Capacity, Load, and Target Reserve Margin

	Duke	Southern Company	Santee Cooper	SCE&G	TVA	AEP_APP	DOM	Yadkin
Nuclear	5,887	6,895	318	2,066	7,832	0	3,501	
Coal and CC*	8,470	37,247	3,974	2,547	19,618	6,155	10,347	
Peaking	4,201	8,943	780	322	5,450	450	4,135	
Hydro	1,127	2,379	457	240	4,254	554	318	215
Pump Storage	2,140	1,186	0	576	1,739	238	3,003	
Interruptible	987	2,600	424	225	1,500	0	230	
Total Summer Capacity	22,812	59,249	5,953	5,976	40,393	7,397	21,534	215
Summer Peak Load	19,476	51,101	5,155	5,138	35,000	6,372	18,686	
Summer Reserve Margin	17.1%	15.9%	15.5%	16.3%	15.4%	16.1%	15.2%	

*includes renewable capacity

The costs of market purchases were calibrated using Progress Energy historical purchases and other market pricing data from the southeast region. As shown in Figure 14, scarcity pricing is based on the shortage in the specific region. As the excess capacity approaches zero, the price of capacity approaches the cost of unserved energy. Such an event is rare but can occur as a function of severe weather, poor unit performance, and significant load forecast error.

Figure 14. Scarcity Pricing Model



Available Transmission Capacity and TRM

The import capability is made up of Available Transmission Capability (ATC) and Transmission Reliability Margin (TRM). ATC is the non firm hourly transmission expected to be available in the market place while TRM is the portion of the transmission system that is held back for reliability needs. TRM is a fixed number while ATC is highly volatile. Due to its highly volatile nature, ATC is represented as a distribution to capture hours when there is little capacity to hours when there is abundance. The distributions used in SERVM are based on historical hours in 2011 during peak periods. It should be noted that these limits do not represent the amount of generation available from neighbors but only serve as the import constraint. Given these constraints, it is expected that the limiting factor will be generation availability from neighbors rather than transmission. However, transmission capability will be a critical sensitivity in the final analysis. See the confidential Appendix for details regarding the values used for ATC and TRM.

H. Carrying Cost of Capacity

The cost of carrying incremental reserves was based on the capital cost, fixed O&M, and estimated transmission upgrades of a 176 MW (summer rating) advanced natural gas CT. The cost assumptions were based on estimates provided by Progress Energy. Since the second unit is always less costly than the addition of a first unit, the assumption was that the first unit costs would be multiplied by 25% and the next unit cost would be multiplied by 75% to develop a weighted average cost to build a four unit site. See the confidential Appendix for details regarding characteristics and costs of the combustion turbine.

I. Operating Reserve Requirements

Operating Reserves are composed of Contingency Reserves and Regulating Reserves. Contingency Reserve and Regulating Reserve requirements for Progress were based on the VACAR Reserve Sharing Agreement and Balancing Authority operational procedures established to ensure compliance with NERC's Reliability Standards BAL-001 and BAL-002. For the VACAR region, the entities maintain a total Contingency Reserve Commitment of 1.5 times the largest unit in VACAR and a Contingency Reserve Requirement of 1.0 times the largest unit. The Requirement ensures compliance with NERC's Reliability Standard BAL-002. The Contingency Reserve Commitment calculated for Progress is 365 MW and the Contingency Reserve Requirement is 243 MW. Progress' Regulating Reserve requirement to ensure compliance with NERC Standard BAL-001 is 120 MW. The resulting summer spinning reserve requirement (145 MW on-line Contingency Reserve and 120 MW Regulating Reserve) is 265 MW.

J. Cost of Unserved Energy

Unserved energy costs were derived based on information from national studies completed for the Department of Energy in 2003 and 2009. The national studies were compilations of other surveys performed by utilities over the last two decades. The national study split the customer classes into residential, small commercial and industrial, and large commercial and industrial. The 2009 study shows higher costs for commercial and industrial consumers compared to 2003. We expect that the costs of outages have risen rapidly in recent history for commercial and industrial customers due to the impact of technology; however both Progress and Astrape questioned the $92.16/kWh values shown in the 2009 Study for Small C&I. Given that Small C&I customers make up 33% of Progress Energy's peak load, applying this value forced the value of unserved energy to rise to a level that neither Astrape nor the company agreed was reasonable. Given the magnitude of the values seen in the 2009 Study, Astrape and Progress were more comfortable with the 2003 Study values and determined the weighted average value of $15.44/kWh was a reasonable base case assumption The calculation is shown in Table 11. As part of the sensitivity analysis, the cost of unserved energy was varied to understand its impact on the optimal reserve margin target.

Table 11. Unserved Energy Costs

	Class Breakdown %	2003 DOE Study 2003$/kWh	2009 DOE Study 2008$/kWh	2003 DOE Study 2016$/kWh	2009 DOE Study 2016$/kWh
Residential	45%	1.15	1.10	1.45	1.27
Small C&I	33%	26.00	79.90	32.79	92.16
Large C&I	21%	15.00	23.80	18.92	27.45
Weighted Average $/kWh				15.44	36.75
Average of Studies $/kWh				26.10	

V. Simulation Methodology

Since most reliability events are high impact, low probability events, a large number of scenarios must be considered. Deterministic selection of extreme events will not give an accurate representation of the operation of any system during such an event, nor would it be possible to estimate a distribution of when such events could occur. For Progress Energy, SERVM utilized 37 years of historical weather and load shapes, 7 points of economic load growth forecast error, and 400 iterations of unit outage draws to represent the full distribution of realistic scenarios. The number of yearly simulation cases equals 37 weather years * 7 load forecast errors * 10 reserve margin levels = 2,590 total cases. For each of these cases, 400 iterations of unit outage draws are performed which means over one million yearly simulations were completed for the analysis. From this analysis, expected reliability costs can be calculated and compared to the cost of adding additional reserves.

A. Case Probabilities

An example of probabilities given for each case is shown in Table 12. It is assumed that each weather year is given equal probability and each weather year is multiplied by the probability of each load forecast error point to calculate the case probability.

Table 12. Case Probability Example

Weather Year	Weather Year Probabilitiy	Load Forecast Error	Load Forecast Error Probability	Total Case Probability (Weather Yr Prob x LFE Prob)
1975	2.70%	-6.23%	1.64%	0.0443%
1975	2.70%	-3.76%	11.29%	0.3051%
1975	2.70%	-1.79%	22.46%	0.6070%
1975	2.70%	0.00%	29.23%	0.7900%
1975	2.70%	1.79%	22.46%	0.6070%
1975	2.70%	3.76%	11.29%	0.3051%
1975	2.70%	6.23%	1.64%	0.0443%
1976	2.70%	-6.23%	1.64%	0.0443%
1976	2.70%	-3.76%	11.29%	0.3051%
1976	2.70%	-1.79%	22.46%	0.6070%
1976	2.70%	0.00%	29.23%	0.7900%
1976	2.70%	1.79%	22.46%	0.6070%
1976	2.70%	3.76%	11.29%	0.3051%
1976	2.70%	6.23%	1.64%	0.0443%

For this study, reliability costs are defined as the following:

1) Carrying Cost of Reserves + Production costs above that of a new CT + Imports above the cost of a new CT + Expected Unserved Energy Costs - Sales above that of a new CT

These components are calculated for each of the above cases and weighted based on probability to calculate an expected reliability cost for the year.

B. Reserve Margin Definition

For this study, reserve margin is defined as the following:

- Reserve Margin = (Resources – Demand) / Demand
  - Demand is the Summer System Peak Load and has been reduced by Load Management (DSM and Energy Efficiency)
  - Resources are defined based on summer ratings and do not include DSM or Energy Efficiency

VI. Base Case Results

A. Physical Reliability Results

From a physical only reliability standpoint, Figure 15 shows Loss of Load expectation in events per year for the base case. The one day in 10 year standard (LOLE = 0.1 events per year) falls at a 14.5% summer reserve margin as shown in Figure 15. Figure 16 and 17 display loss of load hours (LOLH) and expected unserved energy (EUE) at varying levels of reserves. At the 14.5% reserve margin level, LOLH is 0.24 hours per year and EUE is 100 MWh.

Figure 15. Base Case LOLE

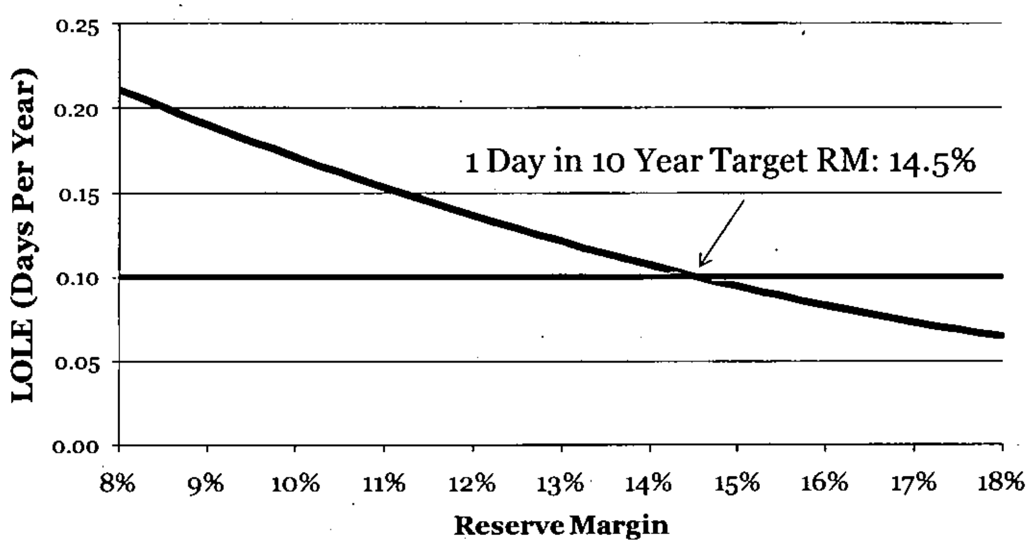


Figure 16. LOLH

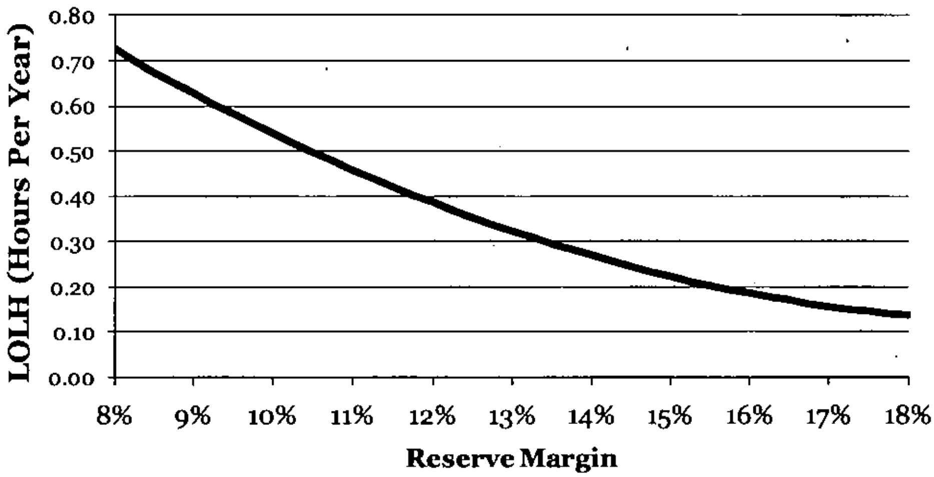
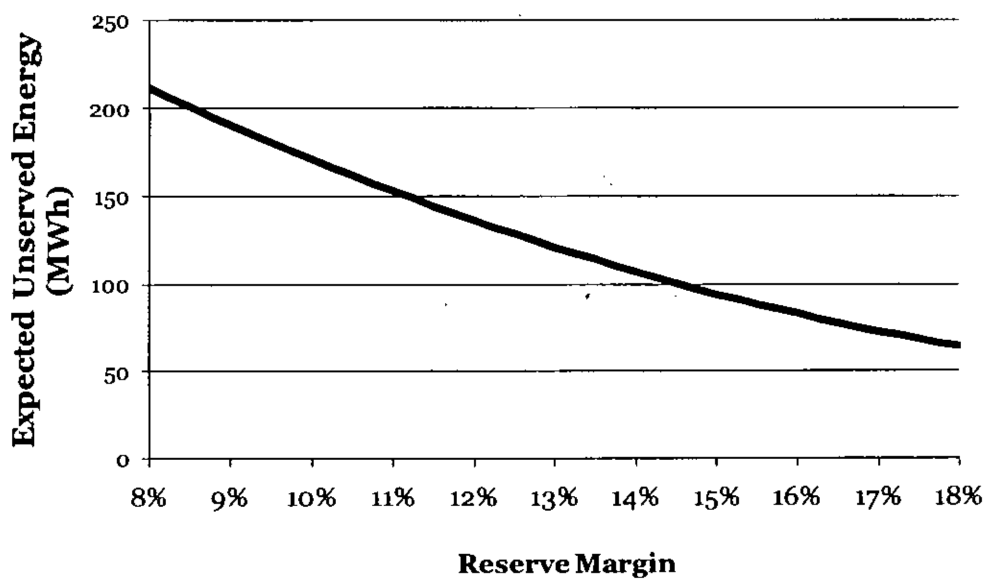


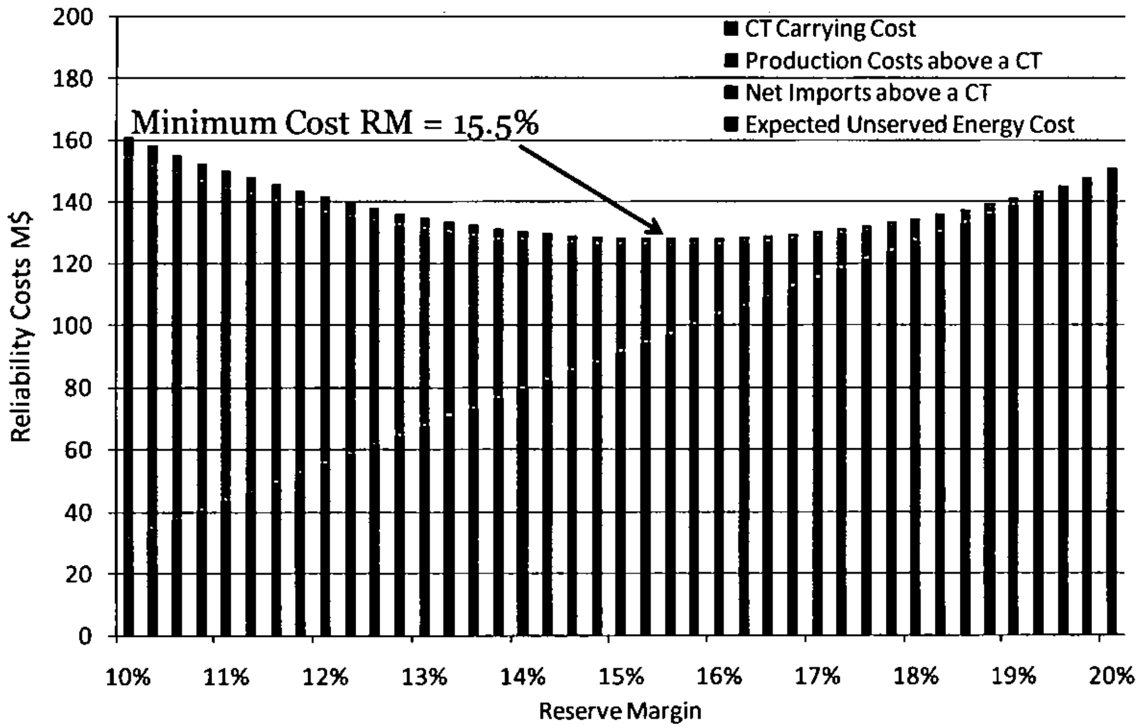
Figure 17. EUE



B. Economic Results

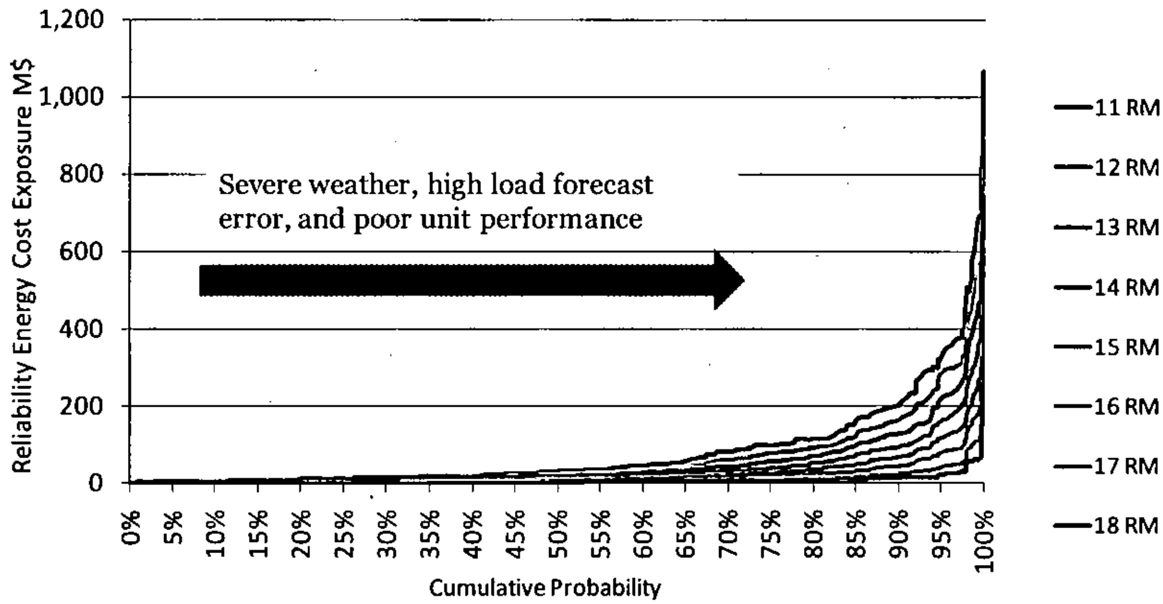
Physical reliability metrics only provide guidance for meeting a few peak load hours over a multi-year study period, and are therefore difficult to calibrate and can be sensitive to neighboring reserve levels, weather diversity, and transmission. To supplement the information provided by the base case LOLE analysis, economic reliability metrics were taken into consideration. Economic reliability costs consider all costs from the next highest cost resource after a marginal CT all the way to the economic impact of shedding firm load. Since additional capacity will have some benefits in every year, this type of analysis is easily calibrated to actual practice and then allows accurate extrapolation to extreme scenarios. The base case economic results are shown in Figure 18. Based on these results, the long-term minimum cost reserve margin based on the weighted average of all results is 15.5%. As reserve margin increases, reliability energy costs (Production cost above a CT, net reliability imports above a CT, and cost of unserved energy) decrease while CT carrying cost increases. It is also important to note the flatness of the cost curves. Since resource additions are too large to perfectly target a reserve margin, some years will inevitably result in reserve margins that are higher than the average economic optimum. The expected financial impact of these additions is not substantial, since the capacity above the weighted average target also brings some financial benefit. For example, the annual expected difference in cost between the 15% reserve margin and 17% reserve margin is only $2 million. This difference in average reliability costs supports a range above the LOLE target from a customer perspective.

Figure 18. Base Case Weighted Average Economic Reserve Margin



The previous figure represents the weighted average cost exposure and does not illustrate the high cost outcomes that can occur at each reserve margin level. While CT costs are mostly fixed, the distribution of reliability energy costs for a given year is volatile, so other confidence levels should be reviewed. While over a 30 year period this may be the optimal reserve margin, any single year can have significant risk at a 15.5% reserve level. Figure 19 shows the reliability energy costs on a probability weighted basis. At a 15% reserve margin, there is a 5% chance that reliability energy costs could exceed $118 million in any given year and a 1% chance that they could exceed $232 million.

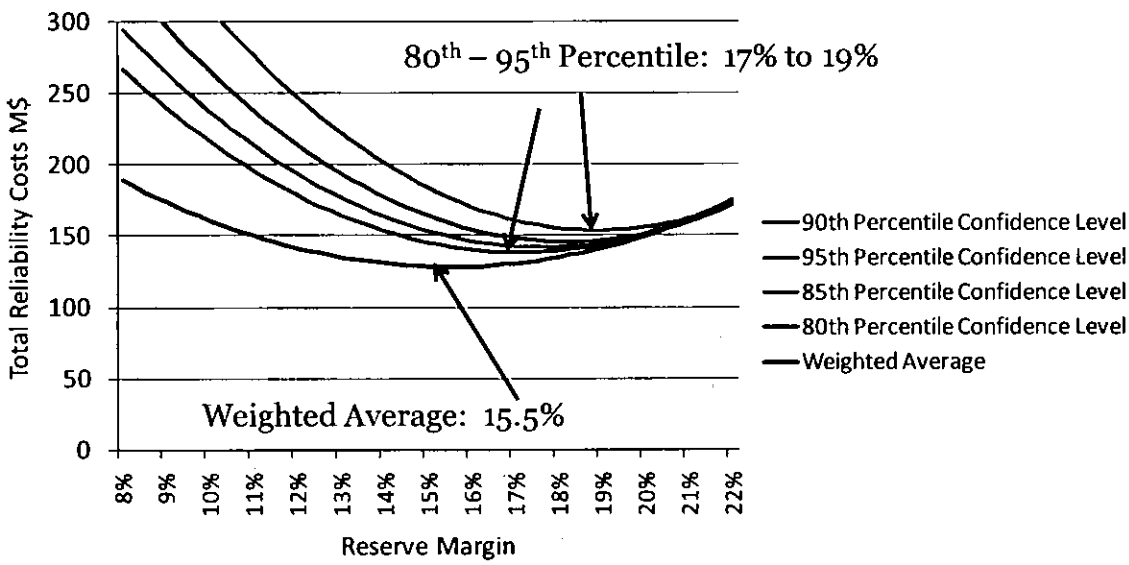
Figure 19. Base Case Reliability Cost Exposure Distribution



Next we examined the optimal economic reserve margin recognizing the different risk profile of energy costs and capacity costs. By comparing capacity costs to reliability energy costs during years with extreme weather or poor unit performance as seen in Figure 19, we assessed the tail benefit of additional capacity. The reliability energy costs seen in Figure 19 were taken at different confidence levels (85%, 90%, 95%, and 99% probabilities) and added to the fixed capacity costs at each reserve margin to form the confidence level curves in Figure 20. This assessment showed that in 10% of all scenarios, Progress Energy would receive an economic benefit by adding efficient natural gas turbines up to a reserve margin of 18.25%. This is shown by the 90% confidence level curve in Figure 20. As stated previously, when we review the weighted average curve in the same figure we can see that by adding capacity to achieve a 17% reserve margin versus a 15% reserve margin, average annual costs only increase by $2 million, but the additional capacity acts as an insurance product to customers. In fact, 10% of the time customers would see their cost exposure decrease by at least $42 million in any given year as seen in Figure 19.

It should be noted that for Progress Energy, the primary benefit driving these high confidence level scenarios is the ability to run the additional efficient natural gas turbines and avoid running existing oil units or purchasing energy at some cost between the gas and oil dispatch cost. However, since the existing oil capacity and demand side management capacity already provide the benefit of avoiding the high impact reliability events such as firm load shed and extreme market purchases, reasonable risk mitigation is achieved at an 80% confidence level, or a 17% reserve margin compared to a 85-95% confidence level for a system that does not have the same oil resource and demand side management penetration.

Figure 20. Risk Adjusted Reserve Margins



VII. Sensitivity Analysis

The following sensitivities were performed on the base case to understand the movement in target reserve margins for both physical and economic metrics.

- No Weather Diversity: All neighbors were given the same load shape as Progress to force all neighbors to peak at the same time.

- 50% ATC: The distributions of ATC were reduced by 50% to understand how transmission was impacting the base case results.
- Island Case: Progress is modeled as an island with no outside assistance.
- +2% Neighbor RM Level: The capacity of all neighbors was increased by a 2% reserve margin.
- -25% System EFOR: The EFOR for all Progress resources was reduced by 25%.
- Marginal Resource Cost: +/- 25%: The capacity costs for the marginal resource was varied by +/-25%.
- EUE Cost: The cost of unserved energy was varied from $5,000/MWh to $25,000/MWh.
- 2023 Study Year: The study year was moved from 2016 to 2023. Load growth and generation expansion were included for each region and escalation in all economic factors such as the cost of EUE, scarcity pricing, and fuel prices was included for this sensitivity.

Table 13 shows the results of each sensitivity simulated. It is seen that the 0.1 LOLE reserve margin is more sensitive to key assumptions than the weighted average economic case. As discussed previously this occurs because LOLE is impacted only by a few hours while economics looks at the broader economic impact of all costs above the costs of a CT.

The results show that LOLE is very sensitive to weather diversity and neighbor assistance while the economic results are less sensitive. Excluding weather diversity shifts the LOLE-based target up by 3.75 percentage point and the economic target up by 0.50 of a percentage point. Dividing the ATC distributions in half has a minor impact, which demonstrates that neighboring capacity is the limiting factor for outside assistance and it is rarely transmission constrained. Increasing neighbor reserve levels by 2% shifts the LOLE-based target down by 6.5 percentage points and the economic target down by 2.25 percentage points. The island sensitivity should be seen purely as an academic exercise demonstrating the level of reserves the company would need to carry if it had no outside assistance. If Progress was a stand-alone utility, then it would need to carry a reserve margin of 23.25%. The decrease of system EFOR by 25% reduces the targets down by 1 percentage point. In studying the year 2023, the target increased by approximately 1 percentage point but still supports the range provided by the base case. It is expected that a long term reserve margin study should evaluate an optimal target three to five years in the future and therefore 2023 would need to be reviewed again in the 2018 to 2020 time frame.

Regarding the economic sensitivities, the cost of unserved energy has little impact on the overall results since firm load shed events are so rare; however, the cost assumed for the marginal CT resource does move the economic reserve margin by approximately +/- 1.5 percentage points. As the marginal resource cost increases, the target reserve margins shift down.

Table 13. Sensitivities

	Physical Metric	Economic Metrics	
	LOLE: 1 in 10 Standard Target RM	Weighted Average Target RM	90% Target RM
Base Case	14.50%	15.50%	18.25%
No Weather Diversity	18.25%	16.00%	19.50%
50% ATC	15.25%	16.75%	19.25%
Island Case	23.25%		
+2% Neighbor RM	8.00%	13.25%	17.25%
-25% System EFOR	13.50%	14.50%	17.25%
2023 Study Year	15.75%	16.75%	19.25%
Marginal Resource Cost: +25%		14.00%	17.50%
Marginal Resource Cost: -25%		17.00%	19.50%
EUE Cost: $25,000/MWh		15.75%	18.50%
EUE Cost: $5,000/MWh		15.25%	18.25%

VIII. Conclusions/Recommendations

Astrape recommends that Progress set its absolute minimum reserve margin at the 14.5% LOLE target (LOLE = 0.1). Since capacity is added in large blocks to take advantage of economies of scale, the actual reserve margin will often be somewhat higher than the minimum. As shown in the charts and data above, a reserve margin target in the range of 14.5% to 17% produces similar total customer costs whether at the low end or high end of the range. To accommodate large resource additions such as nuclear or coal or even combined cycle, the reserve margin would likely rise above the top end of the reserve margin range at 17%. However, the additional production cost and economy of scale benefits provided by such resources would likely justify their addition. Therefore, the recommended target reserve margin range of 14.5% to 17% should not be considered absolute; resource decisions should be made on a case-by-case basis.

The results should be reviewed periodically as there are shifts in generation mix, DSM, intermittent resource penetration, or load shape that could impact results. Provided that the results are greatly impacted by regional reserve margins, it is also recommended that Progress keep a close eye on the surrounding market place. Short term capacity decisions should also be reviewed on a case-by-case basis. Since physical capacity changes can rarely be implemented inside a 3-year window, the cost of any procurement should be weighed against the distribution of reliability events and the distribution of reliability costs associated with not purchasing the capacity. Even in cases when Progress is below its minimum target reserve margin, economic and physical reliability metrics may suggest not procuring additional capacity, or an analysis may suggest purchasing more capacity than is needed to achieve the minimum target.

VIX. Confidential Appendix

A. Hydro Modeling

Hydro Resources (MW)

Region	Unit Name	January	July
East	ROR	0	1
East	Scheduled (Peak Shaving)	96	77
East	Emergency	15	30
West	ROR	1	2
West	Scheduled (Peak Shaving)	101	83
West	Emergency	15	33

Total	228	226

Region	Unit Name	January	July
East	SEPA Scheduled (Peak Shaving)	95	95
West	SEPA Scheduled (Peak Shaving)	14	14

SEPA Total	109	109

B. Unit Outage Rates

The following table shows the energy weighted and capacity weighted system equivalent forced outage rates (EFOR) of the entire Progress Energy fleet. Energy weighted EFORs are typically lower than capacity weighted EFORs because base load resources tend to have better availability than resources that are rarely used. The capacity weighted values are more important for a reliability analysis because it is important to understand the availability of resources during peak conditions. Typically, unit performance improves during the peak season because resources are planned to be available during peak conditions.

System EFOR

	Energy Weighted	Capacity Weighted
EFOR including MO	[redacted]	
EFOR excluding MO		
Peak Season EFOR including MO		
Peak Season EFOR excluding MO		

Nuclear Resource Forced Outage Rates

Unit	Avg Operating Hours	EFOR including MO	EFOR excluding MO	Peak Season EFOR including MO	Peak Season EFOR excluding MO
Brunswick 1	[redacted]				
Brunswick 2					
Harris 1					
Robinson 2					

Baseload and Intermediate Resource Forced Outage Rates

Unit	Avg Operating Hours	EFOR including MO	EFOR excluding MO	Peak Season EFOR including MO	Peak Season EFOR excluding MO
Asheville 1	[redacted]				
Asheville 2	[redacted]				
Mayo 1	[redacted]				
Robinson 1	[redacted]				
Roxboro 1	[redacted]				
Roxboro 2	[redacted]				
Roxboro 3	[redacted]				
Roxboro 4	[redacted]				
Richmond CC 4	[redacted]				
Richmond CC 5*	[redacted]				

*Data only includes 7 months provided a June, 2011 COD

Peaking Resource Forced Outage Rates

Unit	Avg Operating Hours	EFOR including MO	EFOR excluding MO	Peak Season EFOR including MO	Peak Season EFOR excluding MO
Asheville CT 3	[redacted]				
Asheville CT 4					
Blewett CT 1					
Blewett CT 2					
Blewett CT 3					
Blewett CT 4					
Cape Fear CT 1A					
Cape Fear CT 1B					
Cape Fear CT 2A					
Cape Fear CT 2B					
Darlington CT 1					
Darlington CT 2					
Darlington CT 3					
Darlington CT 4					
Darlington CT 5					
Darlington CT 6					
Darlington CT 7					
Darlington CT 8					
Darlington CT 9					
Darlington CT 10					
Darlington CT 11					
Darlington CT 12					
Darlington CT 13					
Lee CT 1					
Lee CT 2					
Lee CT 3					
Lee CT 4					
Morehead City 1					
Richmond County 1					
Richmond County 2					
Richmond County 3					
Richmond County 4					
Richmond County 6					
Robinson CT 1					
Sutton CT 1A					
Sutton CT 2A					
Sutton CT 2B					
Wayne County 1					
Wayne County 2					
Wayne County 3					
Wayne County 4					
Wayne County 5					
Weatherspoon CT 1					
Weatherspoon CT 2					
Weatherspoon CT 3					
Weatherspoon CT 4					

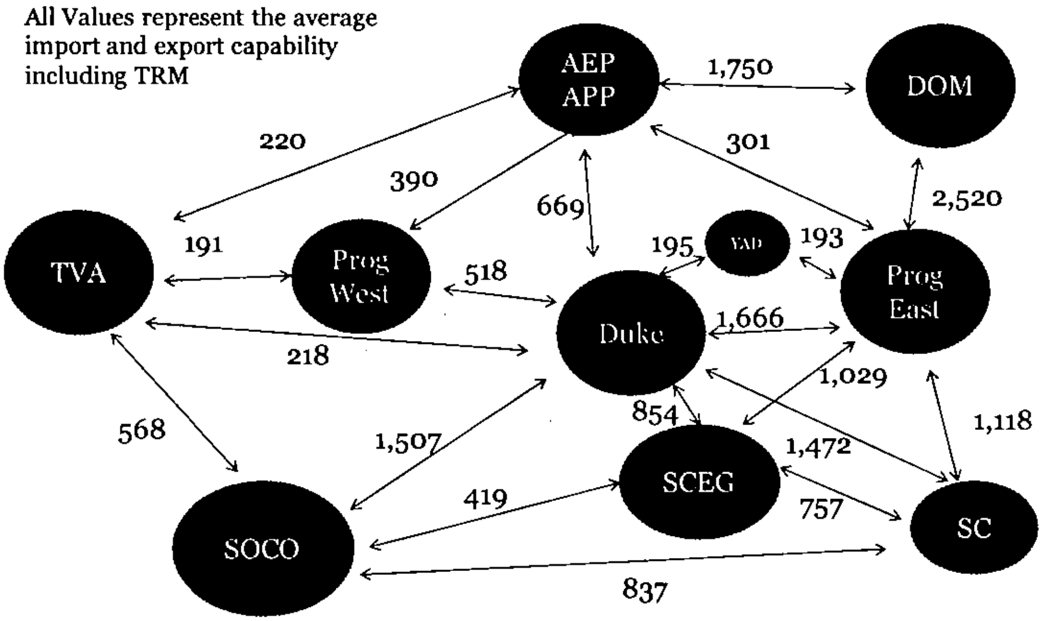
Due to higher regional reserve margins in recent years, the average operating hours of peaking capacity was relatively low. If a unit only runs on average 10 hours a year and has one outage event of 10 hours then the calculated EFOR (repair hours/(repair hours + operating hours)) is 50%. If these peaking resources were needed for several hundred hours it is expected that the EFOR would be much less than 50%. To make this adjustment hours were added to the time to fail distribution which are shown in the following table to represent more reasonable EFOR targets for these units that did not have significant operating histories. Astrape has experienced this issue relative to historical peaking EFORs in all its previous studies and has found that an EFOR between 10% and 20% is a reasonable target for these resources as they are needed more frequently during peak periods.

Peaker EFOR Correction Values

	EFOR Target (%)	Time to Fail Adder (hrs)
Blewett 1	[redacted]	
Blewett 2		
Blewett 3		
Cape Fear 1A		
Cape Fear 1B		
Cape Fear 2A		
Cape Fear 2B		
Darlington 1		
Darlington 13		
Darlington 3		
Darlington 4		
Darlington 9		
Morehead 1		
Richmond 6		
Robinson 1CT		
Sutton 2A		
Sutton 2B		
Wayne 1		
Wayne 2		

C. Available Transmission Capability and TRM by Region

Region	ATC IMPORT (MW)		TRM IMPORT (MW)	TOTAL (MW)
Progress_East	min	1,857		
Progress_East	average	4,418	1,835	6,253
Progress_East	max	6,064		
Progress_West	min	400		
Progress_West	average	1,064	198	1,262
Progress_West	max	1,553		
SOCO	min	474		
SOCO	average	3,424	-	
SOCO	max	4,877		
Santee Cooper	min	1,461		
Santee Cooper	average	4,130	372	4,502
Santee Cooper	max	5,855		
AEP	min	2,127		
AEP	average	3,414	-	
AEP	max	3,960		
Dominion	min	1,965		
Dominion	average	3,636	372	4,008
Dominion	max	4,692		
Duke	min	3,035		
Duke	average	6,096	398	6,494
Duke	max	9,443		
SCEG	min	2,072		
SCEG	average	2,874	372	3,246
SCEG	max	3,093		
TVA	min	470		
TVA	average	1,304	-	1,304
TVA	max	1,576		


All Values represent the average import and export capability including TRM
AEP APP
DOM
TVA
Prog West
Duke
VAD
Prog East
SOCO
SCEG
SC
1,750
220
301
390
669
2,520
191
195
193
518
1,666
218
1,029
568
854
1,118
1,507
1,472
419
757
837

D. Generic Combustion Turbine Characteristics

CT 190 FRAME
All Costs in 2011$

	FIRST UNIT		NEXT UNIT	
Fuel	Natural Gas		Natural Gas	
	Winter	Summer	Winter	Summer
Nameplate Capacity (MW)	196.5		196.5	
Net Unit Capacity, MIN (MW)	101.1		101.1	
Net Unit Capacity, Seasonal (MW)	208.7	176.1	208.7	176.1
Economic Carrying Charge ($/kW)		[redacted]		[redacted]
Transmission ECC ($/kW)		[redacted]		[redacted]
Fixed O & M (Thou $)	[redacted]		[redacted]	
FO&M ($/kW)	[redacted]	[redacted]	[redacted]	[redacted]

LT Construction Esc Rate	2.25%
LT Non-Fuel O&M Esc Rate	2.25%

	2016$
First Unit: ECC + Fixed O&M ($/kW-yr)	[redacted]
Next Unit: ECC + Fixed O&M ($/kW-yr)	[redacted]
Combined: ECC + Fixed O&M ($/kW-yr) (25%/75% Ratio for 1st/Next Unit	[redacted]