An Economic and Reliability Study

of the

Target Reserve Margin

for the

Southern Company System

January 2019

Southern Company

EXECUTIVE SUMMARY

Electric utility customers expect and depend on high levels of service reliability. As such, a prudent utility must have an economically balanced level of generating capacity that both exceeds the peak load and that also meets a minimum reliability threshold. To have this reserve capacity available when it is needed, a utility must plan beyond the upcoming season because the processes to procure capacity, such as building a new unit or procuring a power purchase agreement ("PPA"), can take several years to complete. The purpose of this Economic and Reliability Study of the Target Reserve Margin ("Reserve Margin Study") for the Southern Company System ("System") is to determine the amount of reserve capacity – or the Target Reserve Margin ("TRM") – that should be maintained on the System. The Reserve Margin Study includes the companies that participate in the Intercompany Interchange Contract ("IIC"). Specifically, the Reserve Margin Study includes Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and the portion of Southern Power Company included in the IIC (collectively, the "Operating Companies"). Although the TRM will be used to establish the long-term expansion plan, the 2018 Reserve Margin Study should not be understood to determine one constant reliability index in perpetuity, but rather should be re-evaluated on a periodic basis as the System evolves over time. The results of long-term, constant reliability constraints can be impacted by projected changes in load shapes, unit costs, unit availability, and other factors. The objective is to determine how these constraints affect the next capacity decision, with subsequent re-evaluations modifying downstream decisions, as appropriate.

Traditionally, the TRM has been stated in terms of summer peak demands and summer capacity ratings according to the following formula:

$$TRM = \frac{TSC - SPL}{SPL} x\ 100\%$$

Where:

TRM = Target Reserve Margin;

TSC = Total Summer Capacity; and

SPL = Summer Peak Load.

This traditional representation is essentially a Summer TRM and has been the only reserve margin considered because the System (in aggregate) has always been and remains summer peaking on a

Southern Company

weather-normal basis. However, reserve margins can just as easily be stated in alternate terms. Because of increased reliability risk and different capacity resources during the winter season (see Appendix A), this report introduces and recommends the use of a Winter TRM in addition to the traditional Summer TRM. The Winter TRM is stated and represented by the following formula:

$$Winter\ TRM = \frac{TWC - WPL}{WPL} x\ 100\%$$

Where:

TRM = Target Reserve Margin;

TWC = Total Winter Capacity; and

WPL = Winter Peak Load.

Because winter peak loads are different than summer peak loads (lower for a summer peaking utility) and because winter generating capacity can have different operational characteristics than summer generating capacity, the Winter TRM can be higher than the Summer TRM. For example, the final, approved TRM from the 2015 Reserve Margin Study, which was essentially a Summer TRM, represented an increase in TRM from 15% to 16.25% due primarily to winter reliability issues. If planners had generated a Winter TRM from that study, the resulting reserve margin would have been 26%. *However, such 26% Winter TRM would have represented both the same cost and the same level of reliability as its 16.25% Summer TRM equivalent* – despite the appearances of being a "higher" reserve margin.

Reserve Margins are necessary because of uncertainties in operational conditions. The four primary uncertainties causing this need are:

1) **Weather**: The System's "weather-normal" load forecasts are based on average weather conditions over the past 30+ years. If the weather is hotter than normal during warm seasons or colder than normal during cold seasons, the load will be higher. The System's peak demand can be as much as 6.6% higher in a hot summer year and 22.0% higher in a cold winter year

Southern Company

than in an average year.[1] Drought conditions and temperature-related impacts on unit outputs can also significantly affect the System's load and capacity balance.

2) **Economic Growth**: It is difficult to project exactly how many new customers a utility will have or how much power existing customers will use from season to season. Based on historical projections and actual economic growth, peak demand may grow by[REDACTED]more than expected over a four to five-year period.[2]

3) **Unit Performance**: While the Operating Companies have a tremendous track record in keeping very low forced outage rates for the System, there have been occasions in the last ten years when more than 10% of the capacity of the system has been in a forced outage state concurrently.[3]

4) **Market Availability Risk**: The ability to obtain resources from the market when needed to address a short-term System resource adequacy issue is uncertain. In general, having access to resources in neighboring regions enhances a region's reliability due to load and resource diversity. However, the amount, cost, and deliverability of those resources are subject to the external region's resource-adequacy situation or transmission constraints at any given time. While a region can expect some level of support from its neighbors, each region must carry adequate reserves and manage its own reliability risks. Therefore, there is significant uncertainty regarding the availability of such external support when it is most needed.

While each of these four factors creates a need for capacity reserves on its own, confluence of all these risk factors poses considerable risk. Very high capacity reserves would be required to meet customers' load demands plus operating reserve requirements for all occurrences of such events. However, maintaining such high levels of capacity reserves comes at significant expense and may only eliminate very low probability events. A more appropriate approach to setting the TRM is to minimize the combined expected costs of maintaining reserve capacity, System costs, and customer costs associated with service interruptions, and adjust for the value at risk. A proper evaluation of these costs will result in the Economic Optimum Reserve Margin ("EORM"), properly adjusted for risk. However, that risk-adjusted EORM must also meet minimum reliability criteria thresholds. Common practice in the industry regarding this minimum reliability criteria threshold is to plan for a Loss of Load

---

[1] See Figure A.4 in Appendix A.
[2] See Table I.3 in Section I.
[3] See Figure I.6 in Section I.

Southern Company

Expectation ("LOLE") of no greater than 0.1 days per year - or more commonly referred to in the industry as a one event in ten years criterion ("1:10 LOLE").

To understand and quantify the overlap of the four contributing factors to the need for reserve margins, a system dispatch model, Strategic Energy and Risk Valuation Model ("SERVM"), is utilized. SERVM evaluates the ability of the System's capacity resources to meet load obligations every hour in a year for thousands of combinations of weather, load forecast error, and unit performance scenarios. The model quantifies, in dollar cost, two components of reliability-related costs. These components are:

1. Production Costs, including the cost of generation as well as the cost of purchases, and
2. Reliability Costs, including the cost of customer outages (*i.e.,* expected unserved energy ("EUE") cost), emergency purchases, the cost of not meeting operating reserve requirements, and non-firm outage costs (i.e., the cost of calling demand response resources).

The Production Costs and Reliability Costs, determined by the SERVM model, are then compared to the Incremental Capacity Cost of new generation reserves. The analysis is performed on a range of planning reserve margins from 10% - 20%. With lower reserve margin levels, the import costs and Reliability Costs are high and vary widely, but the Incremental Capacity Cost and its associated generation cost are low. At higher reserve margin levels, the import costs and Reliability Costs are low, but the Incremental Capacity Cost and its associated generation cost are high. The objective of this study is to find the reserve margin where the sum of these costs is minimized (i.e. the minimum cost point), which is referred to as the EORM. The "U-curve" in Figure 1 shows the sum of Production Costs, Reliability Costs, and Incremental Capacity Costs across the range of reserve margin levels studied and demonstrates that the EORM occurs at a summer reserve margin of 15.25%. The figure represents the weighted average costs over all the load, weather, and outage draws simulated and is stated in terms of the traditional, summer-oriented reserve margin.[4]

---

[4] That is, stated in terms of summer capacity ratings and summer weather-normal peak demand.

Southern Company
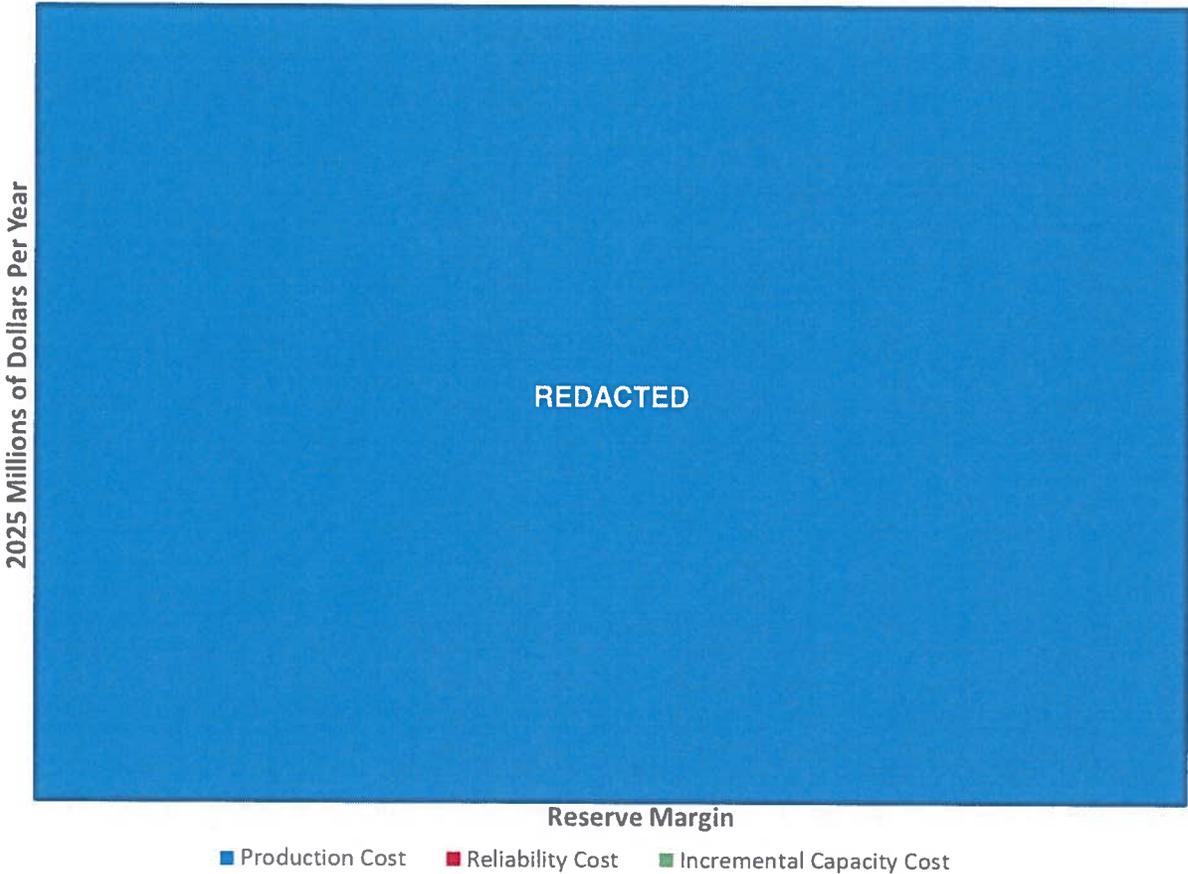
Figure 1. Traditional EORM U-Curve

However, Appendix A discusses in detail the winter reliability risks facing the System. To address those risks, the same analysis was performed from the perspective of a winter-oriented reserve margin.[5] The "U-Curve" in Figure 2 below shows the results of this analysis and demonstrates that the Winter EORM is 22.5%. Although the winter EORM appears to be much higher than the summer EORM, this difference is merely a function of how they were stated (*i.e.*, stated in summer terms vs. stated in winter terms as described above). The EORMs represent essentially the same level of cost and reliability and are therefore essentially equivalent.

---

[5] That is, stated in terms of winter capacity ratings and winter weather normal peak demand.

Southern Company
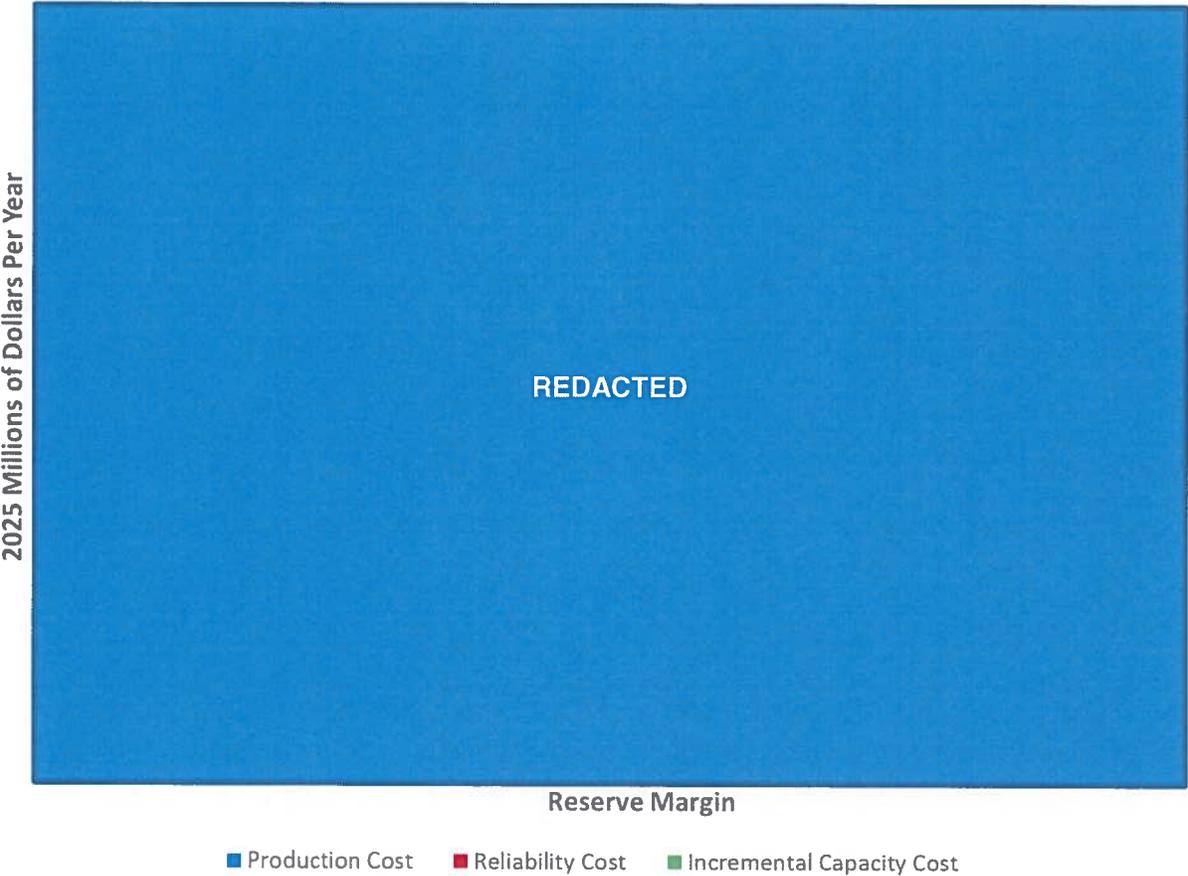
Figure 2. Winter EORM U-Curve

Finally, since winter is the driving factor behind the traditional results, thus leading to a need for a Winter TRM, an analysis was performed to determine what a Summer TRM would be assuming several of the key winter drivers were removed. Not all the winter-oriented drivers can be easily removed from the analysis, but Figure 3 below shows a summer-focused U-Curve with incremental cold weather outages and fuel constraints removed. The results of this analysis show that the EORM for the Summer TRM when these key winter drivers are removed is 14%.

Southern Company
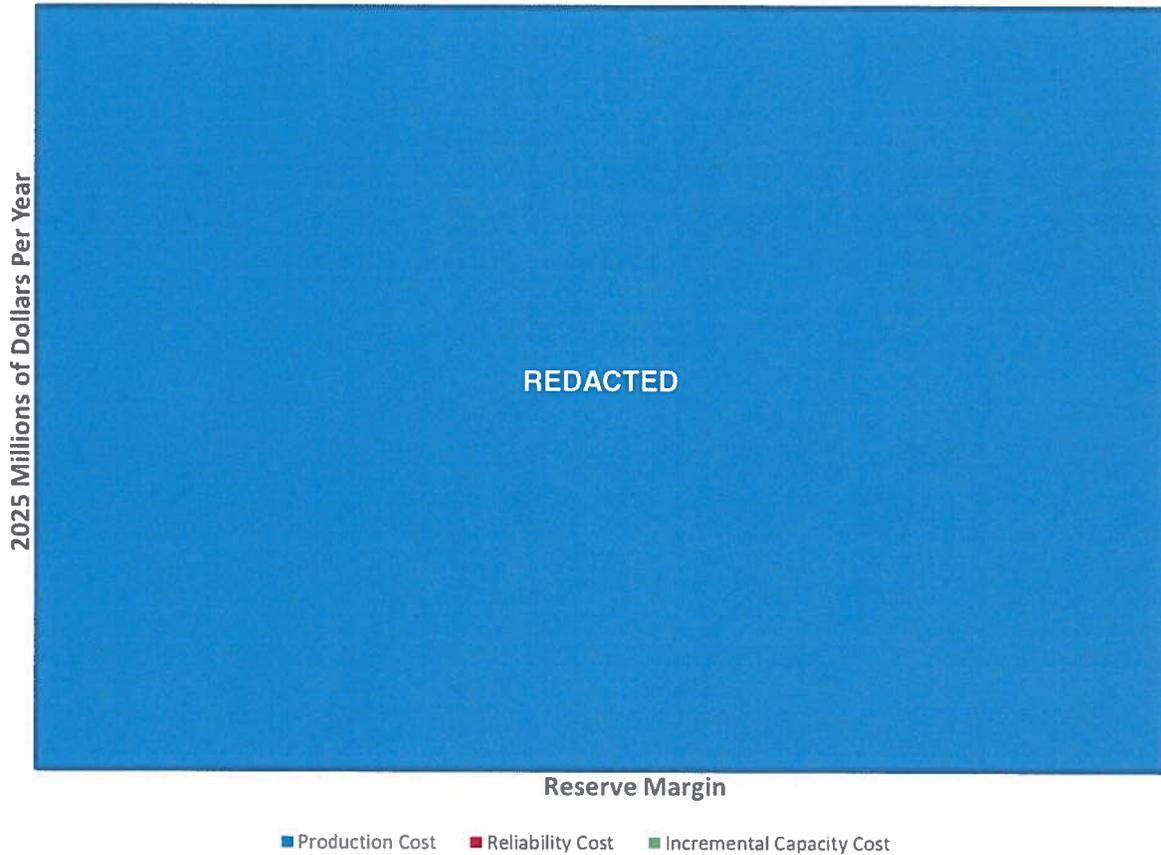
Figure 3. Summer EORM U-Curve

These three U-Curves and their associated analyses serve as the basis for determining a recommendation for the Winter and Summer TRM. Since, as described in Appendix A, winter is the constraining season for reliability on the System, the Winter TRM was considered first.

While the minimum cost of the winter U-Curve falls at 22.5%, the components that were evaluated to develop the U-Curve all have substantially different risk characteristics. The fixed costs of procuring capacity under a long-term PPA or building a new unit are relatively independent of the uncertainties that affect reliability. On the other hand, Production Costs and Reliability Costs can both vary significantly depending on weather, load forecast error, and unit performance.

The trade-off between static Incremental Capacity Costs and highly volatile Production Costs and Reliability Costs is difficult to measure. The expected value of Production Costs and Reliability Costs

Southern Company

is the weighted average of all modeled simulations. For many mild weather or slow load growth scenarios, these Production and Reliability costs will be lower than the expected outcome. However, for more extreme cases, these Production and Reliability costs will be higher than the expected outcome, but lower in probability of occurrence. The significantly higher costs from these cases represent risk that should be considered when recommending a TRM because some of that risk may be mitigated at low incremental cost. The approach taken to mitigate the risk of potential high cost outcomes involves using a risk metric called Value at Risk ("VaR"). VaR is defined as the difference in cost at the expected value and at some specified confidence interval (e.g., the 80th percentile of risk). The VaR analysis looks at the incremental increase in expected cost to move from one reserve margin to the next reserve margin and compares that with the incremental decrease in VaR. The point at which the incremental increase in total system cost[6] equals the incremental decrease in VaR represents the EORM at that confidence interval (as opposed to the EORM at the weighted average). This analysis was performed at various confidence intervals ranging from the 80th confidence interval up to the 95th confidence interval using 0.25% reserve margin increments. As an example of the results of this analysis, the 80th confidence interval resulted in an EORM of 26.0%,[7] which represented an increase in expected case system costs from the 22.5%TRM of **REDACTED**, but would reduce VaR (i.e., exposure to higher than expected future outcomes) on the System by **REDACTED**.

This can be demonstrated graphically by developing the U-Curve at the 80th confidence interval instead of the expected cost. Figure 4 below shows that if you draw the U-Curve at the 80th confidence interval, the EORM is 26.0% instead of 22.5%. Therefore, a reserve margin a few percentage points higher than the expected case EORM benefits customers by eliminating many of the more expensive scenarios (thereby reducing the customers' exposure to cost risk) without significantly increasing expected costs. This outcome represents the risk-adjusted EORM at that confidence interval.

[6] Production Cost plus Reliability Cost plus Incremental Capacity Cost.

[7] Moving from 25.75% to 26.0% resulted in an incremental increase in weighted average costs roughly equal to the incremental decrease in VaR, while moving from 26.0% to 26.25% resulted in an increase in weighted costs that was greater than the decrease in VaR.

Southern Company
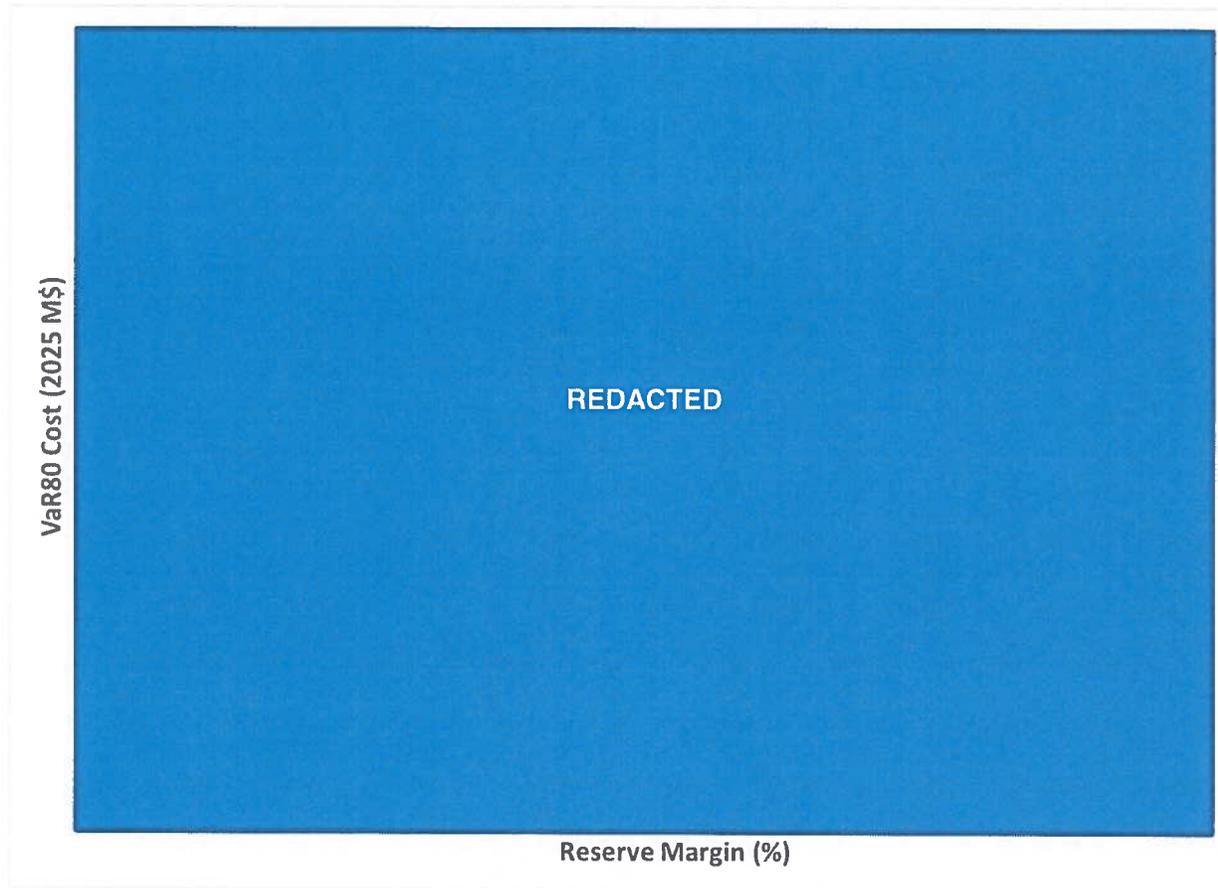
Figure 4. 80% Confidence Interval U-Curve (Winter)

Additionally, the Reserve Margin Study contains reliability metrics such as LOLE. Common practice in the industry is to ensure that the TRM for planning purposes remains above an LOLE threshold of 0.1 days per year (or often referred to as a one in ten – 1:10 – year expectation of loss of load). LOLE has always been considered as part of the reserve margin studies; but in previous studies, the 1:10 LOLE threshold was below the EORM. In the 2018 Reserve Margin Study, the 1:10 LOLE threshold occurs above the EORM in both the summer and winter studies. It is not, however, greater than the VaR80 result. Therefore, in the 2018 Reserve Margin Study, the 1:10 LOLE threshold must be given greater consideration in the determination of the TRM than in previous studies. Figure 5 below shows the relationship between LOLE and reserve margin for the winter-focused study. The figure shows that the curve crosses the 1:10 LOLE threshold (i.e., an LOLE of 0.1 days per year) at REDACTED% reserve margin. It is important that the TRM be above this 1:10 LOLE threshold to ensure an adequate level of reliability on the System. Otherwise, customers may be exposed to potential outages due to

Southern Company

generation shortfalls more frequently than in other regions of the country. Results are similar in the traditional study.
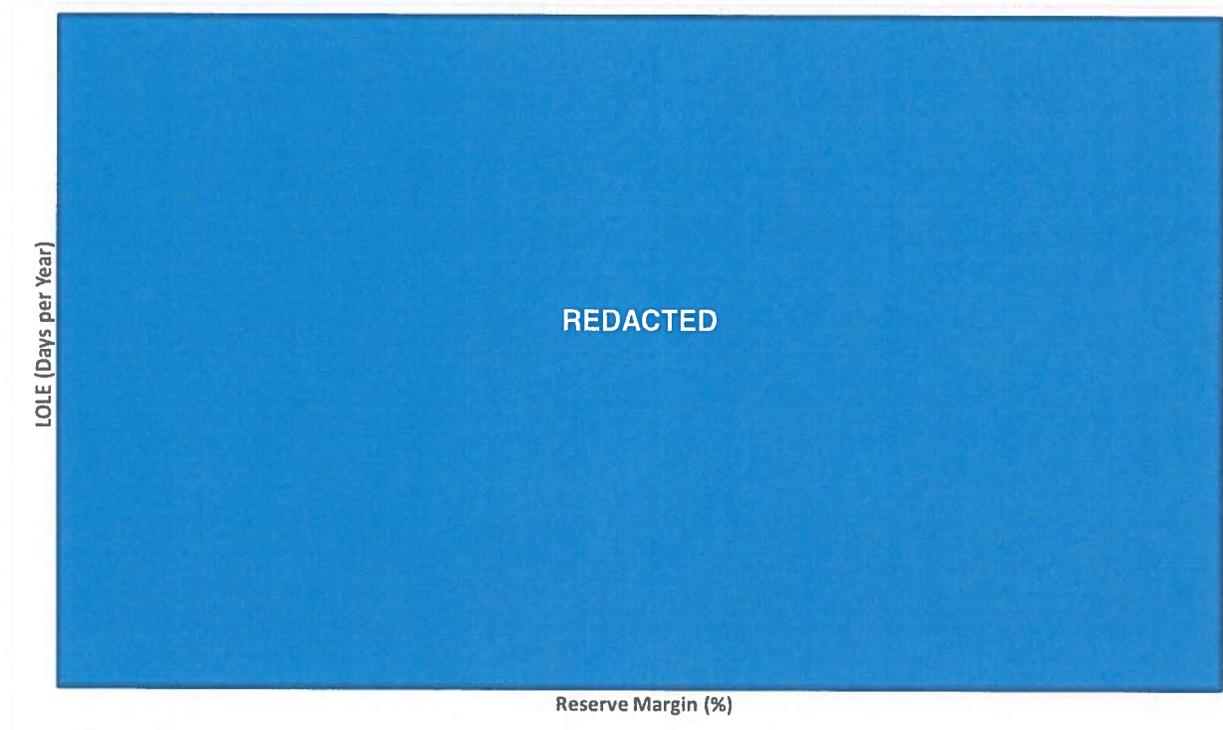
Figure 5. LOLE as a Function of Winter Reserve Margin

The 2018 Reserve Margin Study recommends a long-term Winter TRM of 26% based on the following:

1. The TRM should be greater than the 22.25% 1:10 LOLE threshold to ensure an adequate level of reliability on the System;

2. A reserve margin of 26% represents the risk-adjusted EORM at the 80th confidence interval (the 80th percentile of risk – i.e., VaR80);

3. Compared to the 22.5% expected case EORM, a 26% risk-adjusted EORM reduces VaR at the 80th confidence interval by **REDACTED** while only increasing expected cost by **REDACTED**;

4. Compared to the 25.25% 1:10 LOLE threshold, a 26% risk-adjusted EORM reduces VaR at the 80th confidence interval by **REDACTED** while only increasing expected cost by **REDACTED**; and

Southern Company

5. A 26% Winter TRM is consistent with results from the 2015 Reserve Margin Study,[8] confirming the results of that study.

For the long-term Summer TRM, in addition to consideration of the VaR results, consideration must also be given to the combined summer and winter LOLE. While the Summer-oriented U-Curve indicated an EORM of 14%, the VaR85 calculation resulted in a reserve margin of 16.75%. Therefore, a Summer TRM of up to 16.75% could be justified based on this case. However, LOLE must also be considered. If resources added to the System are available in both the winter and the summer, the LOLE will be in accordance to the curve in Figure 5. However, if the System's winter requirements are met with resources that are not available in summer, then a disconnect between the summer LOLE and the winter LOLE occurs. Therefore, when the combined LOLE for both summer and winter are considered, there is a floor for the Summer TRM that must be maintained to ensure that that the total combined summer and winter LOLE does not fall below the 1:10 LOLE threshold ("Summer TRM Floor"). Figure 6 below shows the 1:10 LOLE threshold Summer TRM Floor for various Winter TRM values.

---

[8] In the 2015 Reserve Margin Study, "An Economic Study of the System Planning Reserve Margin for the Southern Company System" (January 2016), the winter equivalent of the approved 16.25% TRM would have been 26%.

Southern Company
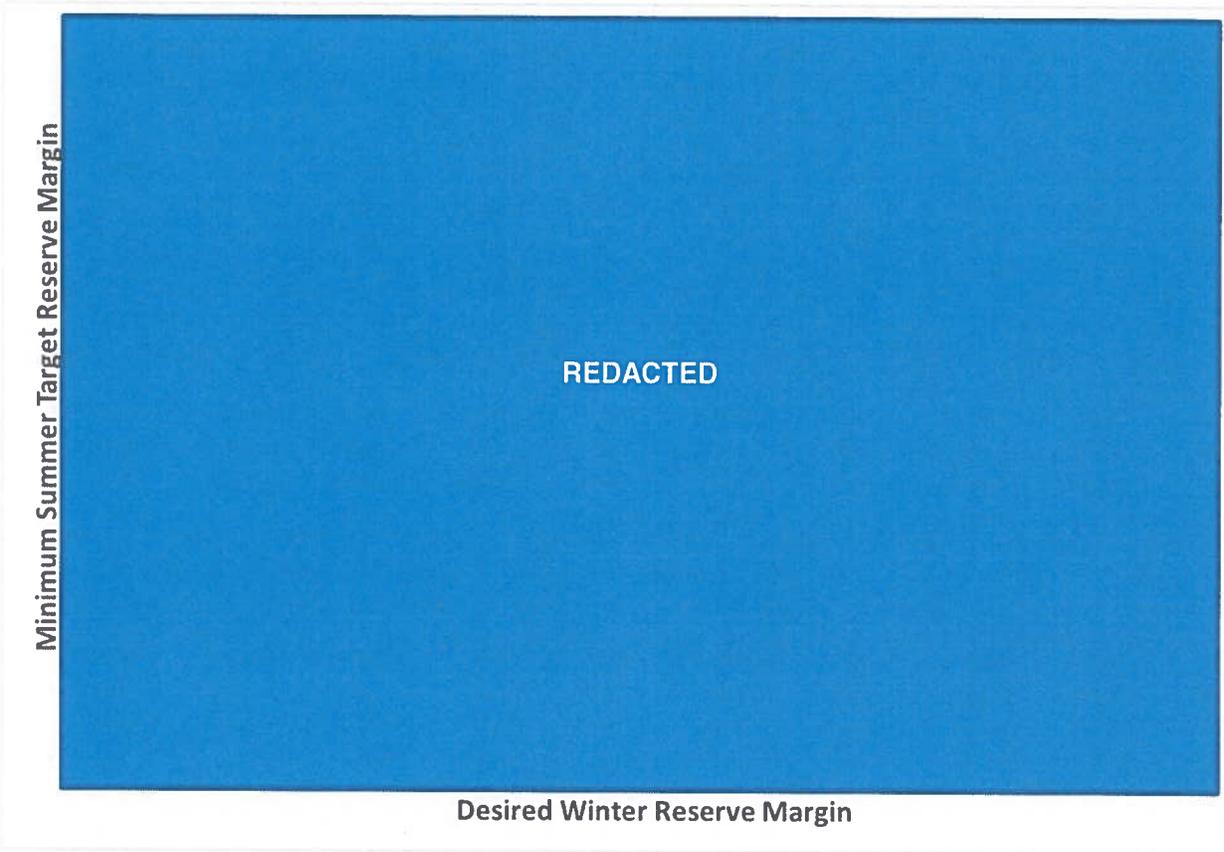
Figure 6. Summer Target Reserve Margin Floor

REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED. Therefore, it is recommended that the current, approved 16.25% TRM (which is already stated in summer terms) remain in place as the Summer TRM.

For short-term planning (inside three years), a sensitivity has been performed which recognizes that there is typically less economic uncertainty in the nearer term (1-3 years out) than in the longer term (4 years out or greater). This sensitivity shows a difference in long-term reserve margin and short-term reserve margin of 0.5% is appropriate.

These recommendations are designed to provide guidance for resource planning decisions but should not be considered absolute targets. As explained throughout this report, various factors may justify

Southern Company

decisions that result in reserve margins above or below the targets mentioned above such as the large size of capacity additions, the availability and price of market capacity, or economic changes.

RECOMMENDATIONS:

1. Implement Seasonal Planning with a Summer TRM and Winter TRM
2. Maintain current approved TRM of 16.25% as the Summer TRM
3. Implement a Winter TRM of 26%
4. Apply a short-term reserve margin with a 0.5% differential from the long-term reserve margins

Southern Company

TABLE OF CONTENTS

Southern Company

Southern Company

Southern Company

LIST OF TABLES

Southern Company

LIST OF FIGURES

Southern Company

Southern Company

I. ASSUMPTIONS

The following sections of this report provide detailed discussions related to the input assumptions associated with the 2018 Reserve Margin Study.

A. Reliability Simulation Model

SERVM was used to calculate Production Costs and Reliability Costs for determining the EORM. These calculations were performed across a broad range of uncertainty risks in load forecast error, weather, unit availability, and performance of non-dispatchable, renewable resources.

Operating events are selected from actual operating history to determine generating unit availability. For each hour in every simulation, each unit will either be operating, on reserve shutdown, partially failed, completely failed, or on scheduled maintenance. The total capacity online and available for purchase is calculated and compared to the load to determine the associated EUE. Performing the random unit status draws for 100 iterations for every hour in the dataset results in average or expected case EUE.

SERVM perfectly matches load and generation, which is impossible to do in the real world. In actual practice, load would be curtailed in large blocks and would be off longer than necessary. If this reality could be incorporated into the model, the expected EUE would likely increase and the EORM would increase. As such, the results of the 2018 Reserve Margin Study should be considered conservative.

B. Study Year

REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED
REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED
REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED
REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED
REDACTED. The representative year selected for this study was 2025.

C. Weather Years

The impact of weather on load was reflected by simulating the System using the 54 historical annual weather patterns from 1962 through 2015. These 54 patterns were then used to develop annual load shapes that would approximate what the load shape would be in the study year (2025) if the weather

Southern Company

pattern matched that of one of the historical years. Two annual load shapes were developed for each of the 54 weather patterns. One assumed the first day of the year occurred on a Tuesday; the other assumed the first day of the year occurred on a Saturday. This was done to vary what day of the week extreme weather conditions were assumed to occur, since extreme weather can theoretically fall either on the weekend or on a peak day. These 108 datasets or "weather years" were given equal probability of occurrence.

The weather year load shapes were developed by using a neural net model to establish the relationship between the weather and load. The neural net was calibrated using weather and load data for the years 2010 through 2015 so that more recent customer usage patterns are reflected. The calibrated neural net was then used to construct the 108 weather year load shapes using the 54 historical weather patterns and two start days. The resulting loads are integrated hourly load shapes.

The temperature data used to develop these load shapes reflect the system weighted average temperature of several locations around the System's footprint. Figure I.1 and Figure I.2 show the historical low winter and high summer temperatures experienced for the 54 weather years modeled.

Southern Company
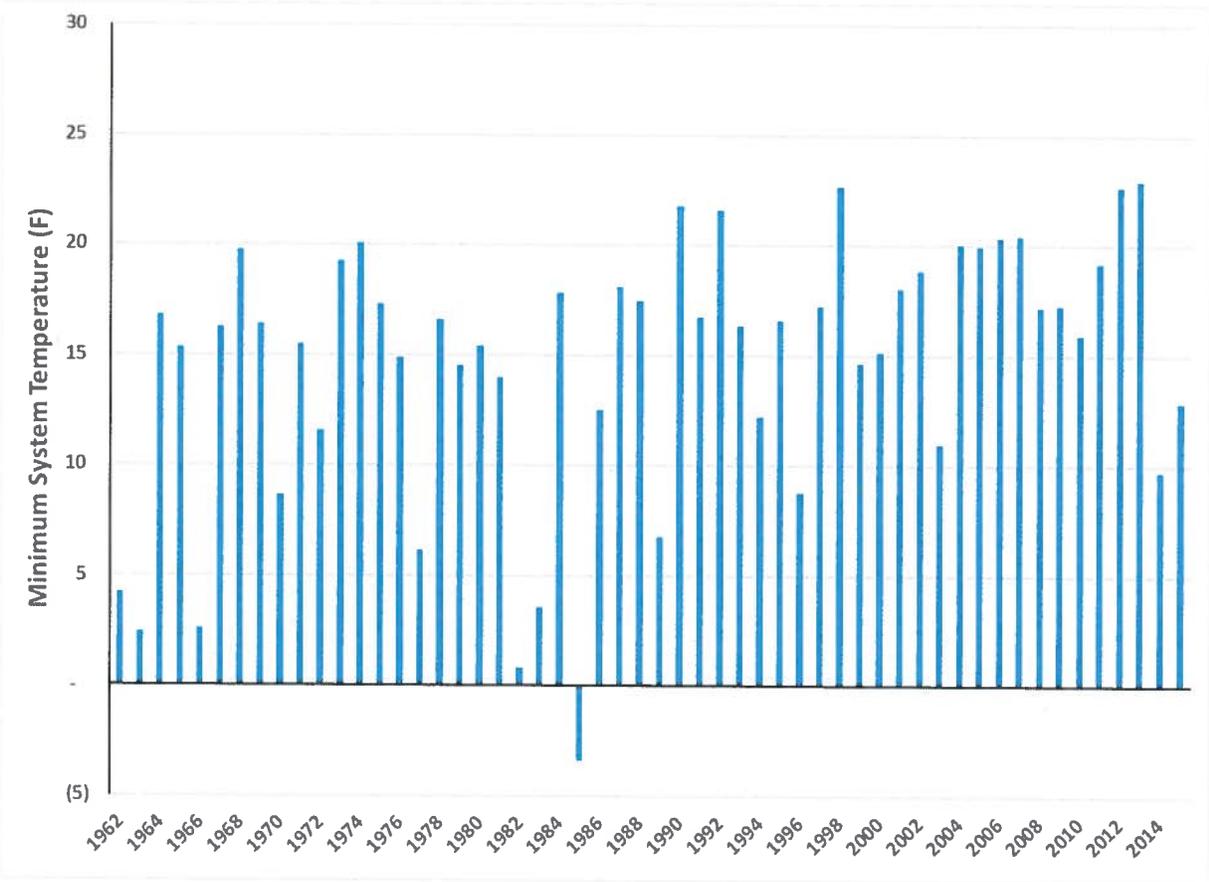
Figure I.1. Historical Low Winter Temperatures

Southern Company
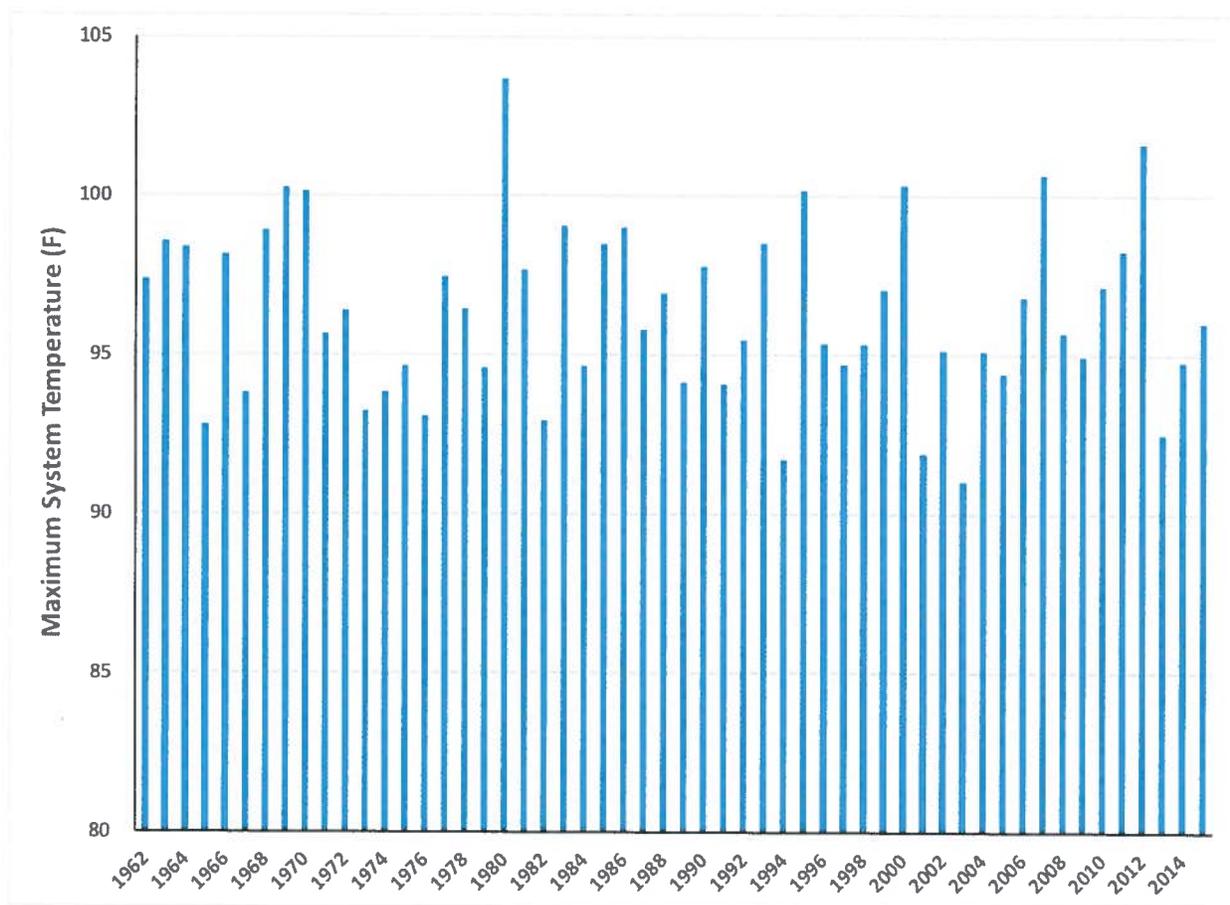
Figure I.2 Historical High Summer Temperatures

D. Market Modeling

The SERVM model allows the System to account for expected support from neighboring regions based on historical load diversity and unit performance diversity. Each weather year modeled uses the actual historical temperature and related load diversity for each region. The System is expected to be able to buy power from neighboring regions that do not typically peak in the same hour as the System if those neighboring regions have economic capacity available to purchase.

Resource adequacy planning requires modelers to build assumptions about the level of support available from neighboring regions. The actual operation of each unit for every neighboring region is modeled in the same way that resources are modeled within the System. Hydro, CTs, base load thermal resources, renewables, and demand response resources ("DRRs") are discretely modeled so that an accurate hourly market price forecast is produced. The CTs that have been modeled as

4

Southern Company

marginal units to the System for purposes of developing the U-Curves are used to avoid purchasing from neighbors at high costs when they are either dispatching high cost resources or in scarcity situations.

The neighboring regions used in the simulation are summarized in Table I.1 (for Summer) and Table I.2 (for Winter) below. The reserve margins modeled in some regions were increased above their published targets to ensure those regions have a reasonable level of reliability (approximately equivalent to the 1:10 LOLE threshold). This is necessary since the regional model used in this analysis does not model a neighboring region's other interconnected regions (*i.e.*, the 2nd tier from the System) to account for the reliability benefit a neighboring region may obtain via purchases from its own neighboring regions. Without the adjustment, the reliability of these regions would be understated and would inappropriately underestimate the System's access to external markets.

Table I.1. Simulation Regions Summary for Summer

Region Name	Summer Reserve Margin Modeled (%)	Peak Load (MW)	Available Transfer Capability into Southern Company Systems (MW)	CBM[9] into Southern Company Systems (MW)
TVA	REDACTED	29425	1126	300
Duke Energy Carolina	REDACTED	20433	217	350
SCEG	REDACTED	5736	125	0
Santee Cooper	REDACTED	4288	332	50
FPL	REDACTED	26145	83	100
Duke Energy FL	REDACTED	8796	76	50
JEA	REDACTED	2579	27	100
Power South	REDACTED	2139	300	-
OPC	REDACTED	5962	5000	-
MEAG	REDACTED	2476	5000	-
TAL	REDACTED	632	11	-
MISO	REDACTED	29014	1957	100

---

[9] Capacity Benefit Margin ("CBM") is a firm import reservation on the transmission system for use during emergencies.

Southern Company

Table I.2. Simulation Regions Summary for Winter

Region Name	Winter Reserve Margin Modeled (%)	Peak Load (MW)	Available Transfer Capability into Southern Company Systems(MW)	CBM into Southern Company Systems (MW)
TVA	REDACTED	30762	1549	300
Duke Energy Carolina	REDACTED	21032	340	350
SCEG	REDACTED	5851	167	0
Santee Cooper	REDACTED	4743	372	50
FPL	REDACTED	23293	187	100
Duke Energy FL	REDACTED	10122	172	50
JEA	REDACTED	2782	61	100
Power South	REDACTED	2581	300	-
OPC	REDACTED	5717	5000	-
MEAG	REDACTED	2240	5000	-
TAL	REDACTED	634	24	-
MISO	REDACTED	25577	2386	100

The topology used for the simulations is in Figure I.3.

Southern Company
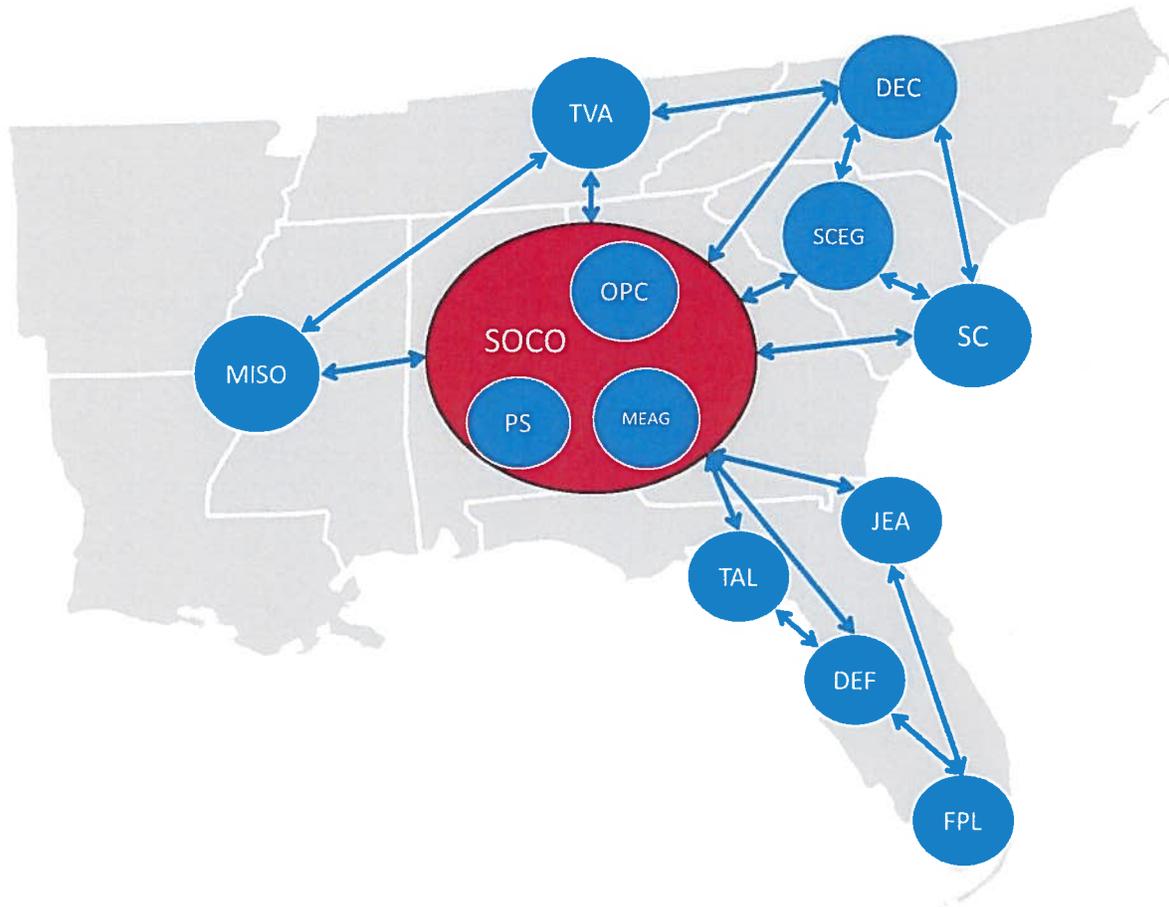
Figure I.3. Simulation Topology

It should be noted that the entirety of the MISO interconnection was not modeled. Rather, only those entities directly interconnected to Southern (Entergy and Cooperative Energy) were modeled. These entities were, however, jointly dispatched as a single entity to reflect operation within the MISO footprint.

Sales and purchase transactions are simulated between regions when the market price in one region is higher than an adjoining region and there is sufficient transfer capability. During extreme scenarios when loads are high, and many units are in a forced outage state, prices can rise substantially higher than the cost of a CT.

Southern Company

Scarcity pricing is the price markets experience when they are short on available capacity and is driven by several complex factors. While the scarcity pricing assumptions used in the Reserve Margin Study have been calibrated to historical scarcity market prices, those relationships may not always hold. During scarcity situations, the System will be subject to the market and, because of the importance of service reliability, is expected to make purchases even at prices well above REDACTED if they are reliably available.

A scarcity pricing curve, developed in conjunction with external consultant "ASTRAPE", used eight years (2010-2017) of historical market purchases to estimate the market purchase cost in scarcity scenarios and is shown in Figure I.4 below. Scarcity prices could rise as high as **REDACTED** if a region experiences a system emergency and shedding firm load is imminent. Scarcity prices are incremental (in addition to) generation costs.

REDACTED
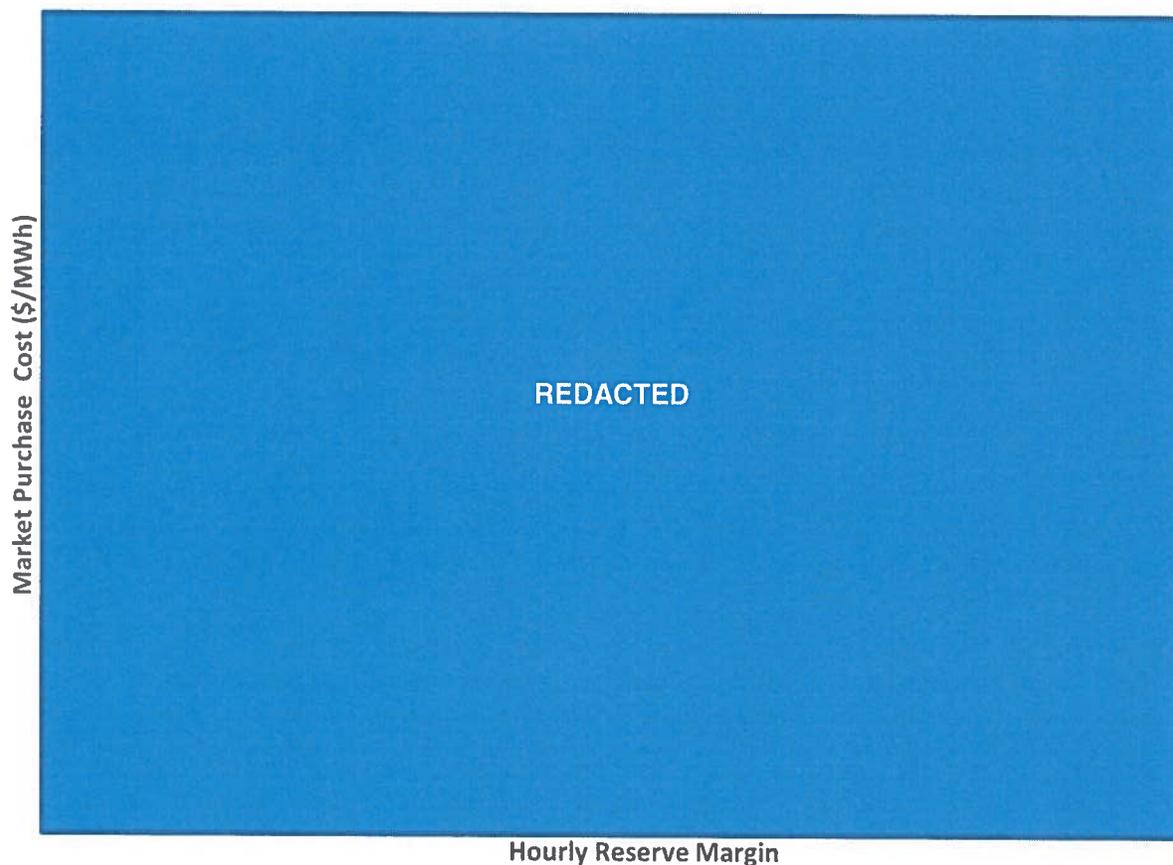
Figure I.4. Scarcity Pricing Curve

Southern Company

During emergency conditions, the System procures as much energy from the marketplace as possible and utilizes other peaking resources such as interruptible customers, voltage control, and emergency hydro. If the System is still short the necessary capacity to meet load plus operating reserves, CBM is utilized to obtain any additional energy that may be available. The System has CBM reservations on ties with TVA, Duke Energy Carolinas, Entergy, South Carolina Public Service Authority, Florida Power and Light, Duke Energy Florida, and JEA totaling 1,150 MW. This CBM capability was modeled and utilized as needed in the analysis.

Despite the load diversity associated with the regional modeling discussed above, the actual availability of purchases from other entities is not always as available as the SERVM model might indicate. Southern Company's Fleet Operations and Trading ("FOT") organization has advised that under extremely high summer load conditions, the availability of purchases in the marketplace is unlikely to exceed REDACTED. Likewise, under extremely high winter load conditions, the availability of purchases in the marketplace is unlikely to exceed REDACTED. These limitations exist for two reasons. First, during such extreme conditions, other market participants may also be experiencing conditions that approach the limits of their own system. Therefore, even though the model may show some available diversity between the regions, those entities may be unwilling to sell that capacity due to the risks and uncertainty on their own systems. Second, during such extreme conditions, there is often a high likelihood of transmission curtailments and so some capacity that may be available may not be deliverable to the system – even if there is transmission interface capability available. These limitations cannot be precisely modeled within SERVM, but a combination of both limits on sales price and hurdle rates between regions has been implemented as a means of addressing these issues.

Merchant capacity has been present in the southeastern United States for over 15 years, but the sporadic nature of its availability requires planners to be conservative in assumptions about its presence in the future. Merchant capacity may be purchased by other load serving entities in the region, may not have firm transmission, or may not have firm fuel supply. For these reasons, merchant capacity was assumed to be unavailable in the base case simulations.

E. Load Forecast Uncertainty

In addition to variation from normal weather, there remains uncertainty in the peak load projections when looking several years into the future. If load grows more quickly than expected, the reserve

Southern Company

margin may not be sufficient unless that growth potential was properly considered in the reserve margin assumptions. Unexpected strength or weakness in the economy is a primary source of this load forecast error ("LFE"). An unforeseen change in electricity utilization and technology (*e.g.* heat pumps, electric transportation, and energy efficiency) can also be a source of LFE.

The LFE assumptions used in the 2018 Reserve Margin Study were updated in the fall of 2017. Load forecast uncertainty REDACTED into the future was estimated using REDACTED of historical data. The System has based its load forecast error assumptions on the REDACTED REDACTED REDACTED forecast growth of the economy and the assumption that there is REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED. For the period REDACTED, the forecasts of REDACTED REDACTED for REDACTED REDACTED into the future were compared with actual REDACTED to determine 21 economic forecast errors. The economic forecast errors were multiplied by REDACTED to determine 21 load forecast errors ranging from a maximum under-forecast error of REDACTED to a maximum over-forecast error of REDACTED. Each of the 21 LFEs has a REDACTED (REDACTED) chance of occurring. By combining and averaging similar LFEs, the 21 LFE points were converted to six LFE points as shown in the following table. For example, points 2 (LFE = REDACTED), 3 (LFE = REDACTED), and 4 (LFE = REDACTED) were combined and averaged to yield REDACTED, and the combined probabilities were summed to achieve a combined probability of REDACTED REDACTED REDACTED. This was done to minimize the total number of runtime simulations that would be required while still considering an accurate distribution of LFE possibilities.

Table I.3. Load Forecast Error

	21 LFEs		6 LFEs	
	LFE	**Probability**	**LFE**	**Probability**
1	REDACTED	REDACTED	REDACTED	REDACTED
2	REDACTED	REDACTED	REDACTED	REDACTED
3	REDACTED	REDACTED		
4	REDACTED	REDACTED		
5	REDACTED	REDACTED	REDACTED	REDACTED
6	REDACTED	REDACTED		
7	REDACTED	REDACTED		
8	REDACTED	REDACTED		
9	REDACTED	REDACTED		
10	REDACTED	REDACTED		
11	REDACTED	REDACTED		
12	REDACTED	REDACTED	REDACTED	REDACTED

Southern Company

13	REDACTED	REDACTED		
14	REDACTED	REDACTED		
15	REDACTED	REDACTED		
16	REDACTED	REDACTED		
17	REDACTED	REDACTED	REDACTED	REDACTED
18	REDACTED	REDACTED		
19	REDACTED	REDACTED		
20	REDACTED	REDACTED	REDACTED	REDACTED
21	REDACTED	REDACTED		

Using this distribution, the minimum and maximum LFE values used in this study are REDACTED and REDACTED of the expected value, respectively.

F. Generating Unit Capacity Ratings

Unit ratings are traditionally established for both the summer and winter seasons. Summer ratings are generally established to correspond to output under 95°F ambient temperatures. Table I.4 below shows the summer ratings associated with the nuclear, coal, and gas steam resources on the System. Only resources for which Georgia Power has ownership or contractual rights are specifically named. Other System resources are designated "SOCO Resource" in Table I.4.

Table I.4. Nuclear, Coal, and Gas Steam Unit Ratings

Unit Name	Unit Category	Peak Rating@95F (MW)
BOWEN_1	Coal	700
BOWEN_2	Coal	700
BOWEN_3	Coal	876
BOWEN_4	Coal	876
HATCH_1	Nuclear	438.88
HATCH_2	Nuclear	442.38
SCHERER_1	Coal	72.24
SCHERER_2	Coal	72.24
SCHERER_3	Coal	860
SOCO RESOURCE	Coal	362
SOCO RESOURCE	Coal	738.5

Southern Company

SOCO RESOURCE	Coal	75
SOCO RESOURCE	Coal	299
SOCO RESOURCE	Coal	475
SOCO RESOURCE	Coal	502
SOCO RESOURCE	Coal	502
SOCO RESOURCE	Coal	128.76
SOCO RESOURCE	Coal	134.55
SOCO RESOURCE	Coal	74.94
SOCO RESOURCE	Coal	74.94
SOCO RESOURCE	Coal	832
SOCO RESOURCE	Coal	718.7
SOCO RESOURCE	Coal	656.24
SOCO RESOURCE	Coal	651.74
SOCO RESOURCE	Coal	658.83
SOCO RESOURCE	Coal	658.83
SOCO RESOURCE	Nuclear	79
SOCO RESOURCE	Nuclear	83.47
SOCO RESOURCE	Nuclear	84.12
SOCO RESOURCE	Nuclear	102.89
SOCO RESOURCE	Nuclear	103
SOCO RESOURCE	Nuclear	41.54
SOCO RESOURCE	Nuclear	41.54
SOCO RESOURCE	Nuclear	874
SOCO RESOURCE	Nuclear	877
VOGTLE_1	Nuclear	538.2
VOGTLE_2	Nuclear	539.14
VOGTLE_3	Nuclear	503.61
VOGTLE_4	Nuclear	503.61
WANSLEY_1	Coal	459.03
WANSLEY_2	Coal	459.03
YATES_6	Gas	350.5
YATES_7	Gas	348.5

Winter ratings for nuclear and steam units are generally unchanged from the summer ratings. Ratings for CT and CC resources, however, can vary significantly depending upon the ambient temperature.

Southern Company

Official winter ratings for CT and CC resources are established to correspond to output at 40°F ambient temperatures. Those ratings are shown in Table I.5 and Table I.6 below.

Table I.5. System CT Ratings

SYSTEM CT RATINGS		
Unit Name	Peak Rating@95F (MW)	Peak Rating@40F (MW)
ADDISON 1	149	171.4
ADDISON 3	148	170.2
BOULEVARD_1	14	16.1
DAHLBERG_10	75.2	86.5
DAHLBERG_2	74	85.1
DAHLBERG_4	73.5	84.5
DAHLBERG_6	74.9	86.1
DAHLBERG_8	74	85.1
EX_HEARD_CTY_1	157.5	181.1
EX_HEARD_CTY_2	157.5	181.1
EX_HEARD_CTY_3	157.5	181.1
EX_HEARD_CTY_4	157.5	181.1
EX_HEARD_CTY_5	157.5	181.1
EX_HEARD_CTY_6	157.5	181.1
MCDON_3A	36	41.4
MCDON_3B	36	41.4
MCINT_CT_1	82.2	94.5
MCINT_CT_2	82.2	94.5
MCINT_CT_3	82.2	94.5
MCINT_CT_4	82.2	94.5
MCINT_CT_5	82.2	94.5
MCINT_CT_6	82.2	94.5
MCINT_CT_7	82.2	94.5
MCINT_CT_8	82.2	94.5
MCMANUS_3A	46	52.9
MCMANUS_3B	46	52.9
MCMANUS_3C	46	52.9

Southern Company

MCMANUS_4A	46	52.9
MCMANUS_4B	46	52.9
MCMANUS_4C	46	52.9
MCMANUS_4D	46	52.9
MCMANUS_4E	46	52.9
MCMANUS_4F	46	52.9
PV_MONROE_1	150.9	173.6
PV_MONROE_2	158.4	182.2
PV_WALTON_1	149	171.4
PV_WALTON_2	149	171.4
PV_WALTON_3	148.9	171.2
PV_WASHINGTON_2	155	178.3
PV_WASHINGTON_3	154.6	177.7
ROBINS_1	80	92
ROBINS_2	80	92
SOCO RESOURCE	158	181.7
SOCO RESOURCE	158	181.7
SOCO RESOURCE	158	181.7
SOCO RESOURCE	158	181.7
SOCO RESOURCE	180	207
SOCO RESOURCE	185	212.8
SOCO RESOURCE	183	210.5
SOCO RESOURCE	183	210.5
SOCO RESOURCE	149	171.4
SOCO RESOURCE	146	167.9
SOCO RESOURCE	47.5	54.6
SOCO RESOURCE	47.5	54.6
SOCO RESOURCE	74.8	86
SOCO RESOURCE	74.7	85.9
SOCO RESOURCE	74.7	85.9
SOCO RESOURCE	55	63.3
SOCO RESOURCE	40	46
SOCO RESOURCE	15	17.3
SOCO RESOURCE	20.6	23.7
SOCO RESOURCE	19.6	22.5
SOCO RESOURCE	20.3	23.3

Southern Company

SOCO RESOURCE	25.3	29.1
SOCO RESOURCE	25.3	29.1
SOCO RESOURCE	36.4	41.8
SOCO RESOURCE	35.5	40.8
SOCO RESOURCE	108	124.2
SOCO RESOURCE	49.9	57.4
SOCO RESOURCE	48.8	56.2
SOCO RESOURCE	68.3	78.5
SOCO RESOURCE	69.3	79.7
SOCO RESOURCE	27.1	31.1
SOCO RESOURCE	27.1	31.1
SOCO RESOURCE	25	28.8
SOCO RESOURCE	25.8	29.7
SOCO RESOURCE	25.6	29.4
SOCO RESOURCE	25.3	29.1
SOCO RESOURCE	26.1	30
SOCO RESOURCE	26.1	30
SOCO RESOURCE	3.2	3.7
SOCO RESOURCE	16	18.4
SOCO RESOURCE	85	97.8
SOCO RESOURCE	84	96.6
SOCO RESOURCE	82	94.3
SOCO RESOURCE	81	93.2
SOCO RESOURCE	82	94.3
SOCO RESOURCE	81	93.2
SOCO RESOURCE	80	92
SOCO RESOURCE	83	95.5
SOCO RESOURCE	82	94.3
SOCO RESOURCE	154	177.1
SOCO RESOURCE	100	115
SOCO RESOURCE	75	86.3
SOCO RESOURCE	32	36.8
SOCO RESOURCE	32	36.8
SOCO RESOURCE	29.9	34.4
SOCO RESOURCE	33	38
WILSON_1A	41	47.2

Southern Company

WILSON_1B	56	64.4
WILSON_1C	49	56.4
WILSON_1D	41	47.2
WILSON_1E	54	62.1
WILSON_1F	54	62.1

Table I.6. System CC Ratings

SYSTEM CC RATINGS		
Unit Name	Peak Rating@95F (MW)	Peak Rating@40F (MW)
HARRIS_1	628	697.1
HARRIS_2	567	629.4
MCDON_4	821	911.3
MCDON_5	823	913.5
MCDON_6	826	916.9
MCINTOSH_10	660.6	733.3
MCINTOSH_11	657.6	729.9
SOCO RESOURCE	550	616
SOCO RESOURCE	557.1	624
SOCO RESOURCE	885	885
SOCO RESOURCE	537.7	602.2
SOCO RESOURCE	556.8	623.6
SOCO RESOURCE	128.1	128.1
SOCO RESOURCE	140.1	140.1
SOCO RESOURCE	595	660.5
SOCO RESOURCE	242.5	269.2
SOCO RESOURCE	213.2	236.7
SOCO RESOURCE	679.4	754.1
SOCO RESOURCE	328	370.6
SOCO RESOURCE	577	640.5
SOCO RESOURCE	594.5	659.9
SOCO RESOURCE	379	420.7

Southern Company

Nevertheless, SERVM has features that can utilize the ambient temperature curves so that the actual output at the simulated system temperature can be modeled. Figure I.5 below shows the ambient temperature curves (on a per unit output basis) that were modeled within SERVM.[10]
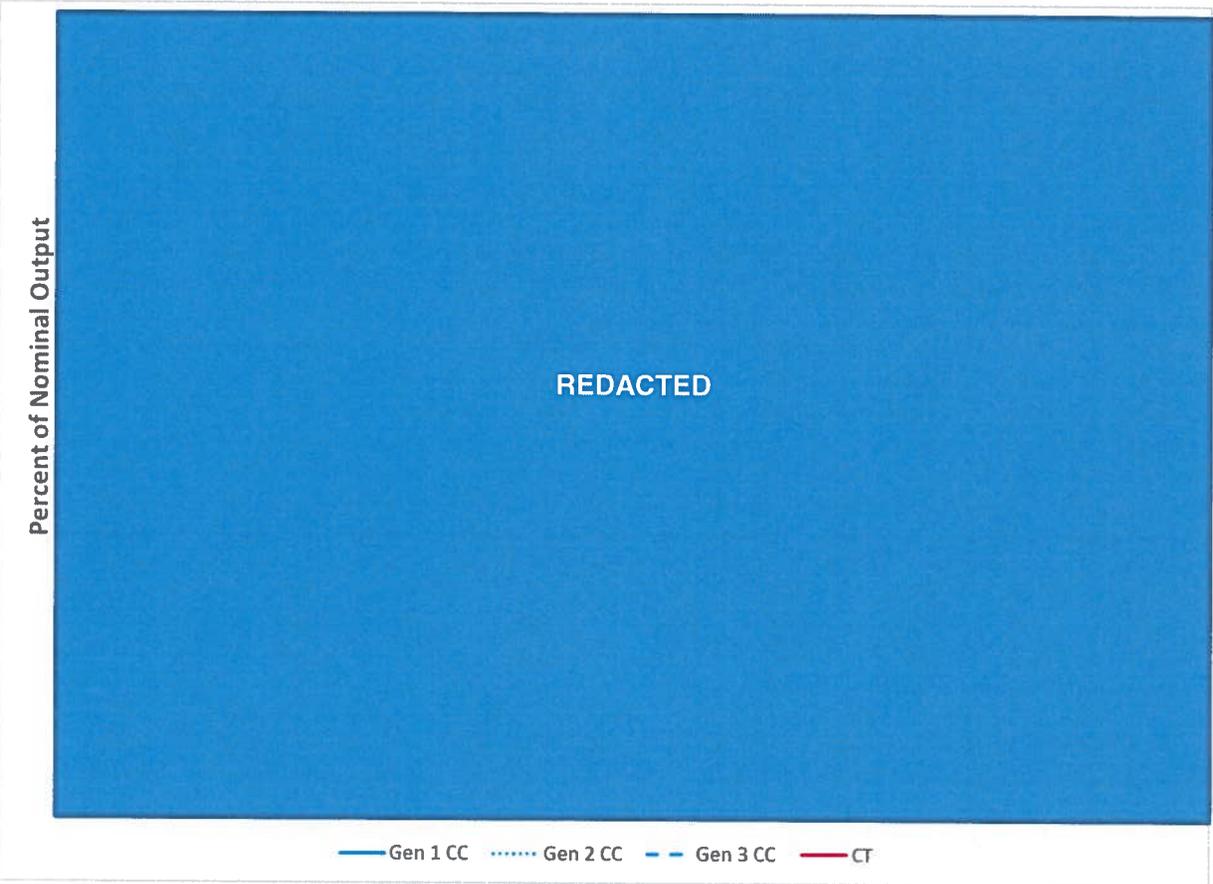
Figure I.5. Ambient Temperature Output Curves

---

[10] One or two CCs have unique designs resulting in their own, unique ambient temperature output curve. Those curves are not shown on the chart.

Southern Company

G. Generating Unit Outage Rates

Generating units typically operate for a period, fail, are repaired, and then operate again. For example, a unit may run from 500 to 1,500 hours before it fails, take from 3 to 500 hours to repair, then run again for 500 to 1,500 hours.

Forced outage and maintenance outage data for the 2018 Reserve Margin Study consist of a series of observations of historical outage events from 2006-2016. This data is assembled into time-to-fail ("TTF") and time-to-repair ("TTR") distributions.

Typical data for a unit might have up to five dozen entries in the TTF input data record, ranging from just a few hours to as many as 12,000 hours. Likewise, the typical data will contain a corresponding amount of entries in the TTR distribution, ranging from one to 2,500 hours. As the model processes chronologically, it will randomly choose a TTF duration from the first data record and then randomly choose a TTR duration. Individual unit operation, therefore, is a direct reflection of what has happened over approximately ten years. Since units are independent of each other, it is possible that many units can be down at once. An example of this type of input data for a steam unit is shown in Table I.7.

Table I.7. Steam Unit Sample Time to Fail and Time to Repair Data

Unit Name	Off-Peak Time-to-Fail (hours)	Off-Peak Time-to-Repair (hours)
Sample Plant	2747	4
	1839	5
	6710	11
	573	4
	333	5
	530	1
	233	2
	215	2
	752	1
	3710	6
	1338	2

Southern Company

Most steam units have their own specific outage history. However, the outage history of similar units has been combined to get a robust set of data from which to take random outage draws. Units with similar history and units for which no outage history was available were modeled using a similar reference unit.

Partial outages are modeled using the same rigorous approach that is used for full outages. A distribution is built for TTF events, TTR events, and the percentage derate. During the simulation, full outages and partial outages are tracked and randomly drawn.

The availability data for the System's "CC" units are modeled similarly to steam, with appropriate outage and derate TTF and TTR data. Additionally, in real-time operations, the supplemental modes (*i.e.*, full pressure ("FP") and power augmentation ("PA") of a CC) are dispatched separately from the base operating mode. The supplemental modes have a higher heat rate value and, therefore, tend to be dispatched during the same demand periods as CTs.

CT unit availability is generally driven by start failures. Once a CT starts, it is rare that it fails during run-time. Within SERVM, all CT availability data has been modeled as a startup probability with TTR data based on real observations. CT data include startup probabilities ranging from 85% to 99%. Repair data range from 8 to 93 entries in the TTR input data records with values ranging from less than an hour to nearly 100 hours.

To further refine outage rates, SERVM allows these historical TTF and TTR values to be scaled in aggregate to achieve an expected outage rate. The historical TTF and TTR values were thus scaled to get outage rates expected for each unit class (see Table I.8 below).

As the model progresses chronologically, it randomly chooses a time to fail duration from the TTF data record and then randomly chooses TTR duration (for CTs, the failure is determined by a probability draw when the startup is initiated and then the TTR is chosen randomly). Individual unit operation, therefore, is a direct reflection of what has happened over the selected sample years of data. The resulting forced outage rates, ratios of failed hours to operating hours, or ratios of failed hours to total hours are thus outputs of the model rather than inputs. Because forced outage rates are an output of the model, there can be minor differences in the resulting EFOR from case to case, but with sufficient outage draw iterations in the simulation, the resulting EFOR should converge to an expected value.

Southern Company

The table below shows the resulting EFOR from one of the simulated runs, excluding any impacts from cold weather-related outages, which should be approximately the same in all cases.

Table I.8. Approximate EFOR by Unit Class

Unit Class	EFOR (%)
Nuclear	1.9
Coal	2.9
Gas Steam	2.2
Combined Cycle	1.6
CTs	5.0
Total System	2.7

The SERVM simulation randomly selects failure events and operating events for each unit. For every hour, certain units will be operating, and other units will be in a failure state. To ensure the model predicts these events accurately, a comparison was made of the simulated outage probability to the actual outage probability. This comparison, shown in Figure I.6, confirms that the modeled outage rate is consistent with the historical outage rate and indicates that the impact of outage events is adequately modeled.
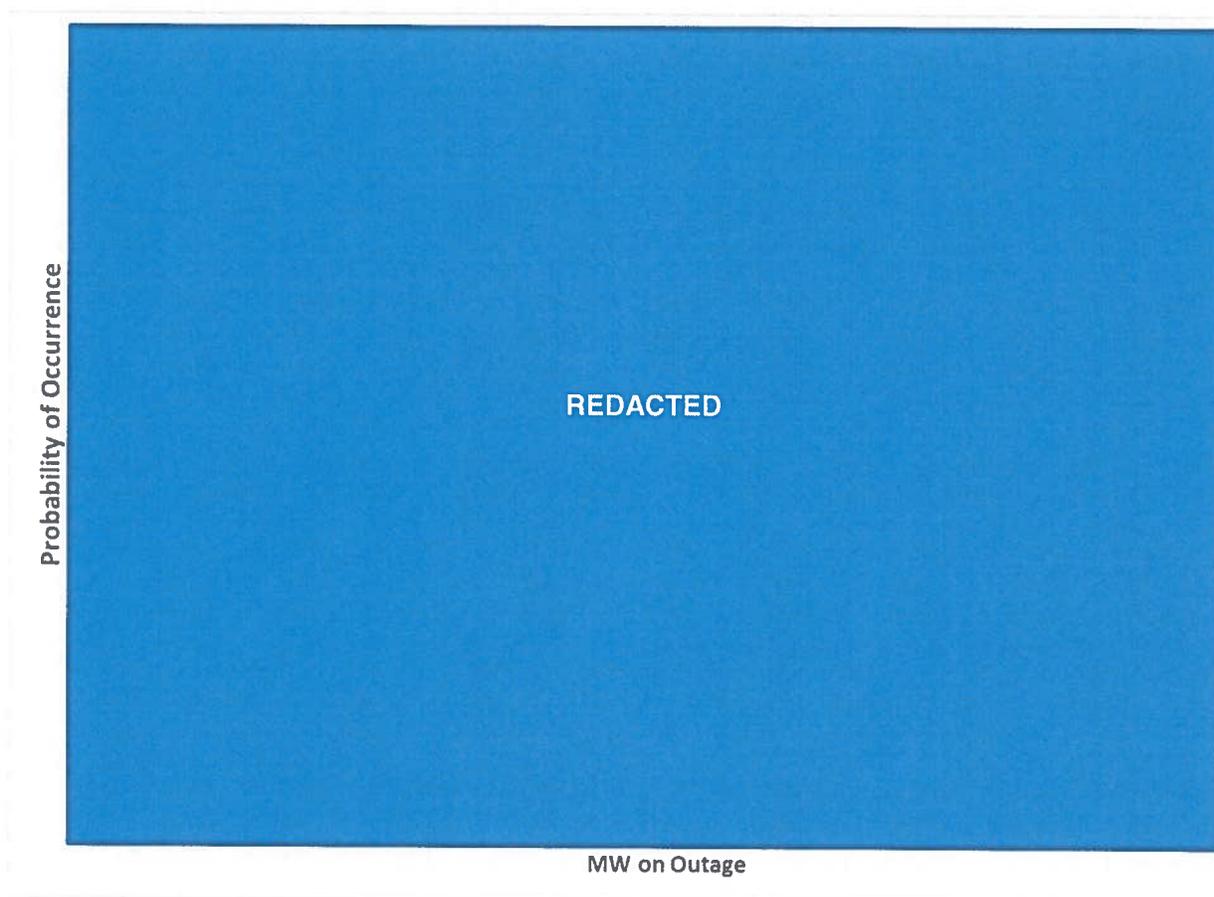
Figure I.6. Unplanned Outage Probability

H. Incremental Cold Weather Outages

The discussion of outage data in the previous sections describes the "base" level of outage expected across the year. However, history has demonstrated that under extremely cold conditions, outage rates can increase as coal piles and pipes begin to freeze, as oil thickens to the point that it will not flow sufficiently to operate a facility, or as instrumentation and controls or other plant equipment begin to freeze. These situations do not materialize until weather conditions are extreme, and these extreme weather conditions are less common. When they occur, however, the outage impacts can be significant and can increase in an exponential manner. Historically, these incremental outages have materialized at system weighted temperatures roughly REDACTED and below. However, efforts to minimize these impacts have been made in recent years and implemented across the system. Based on these efforts, it is expected that performance improvements will be such that these incremental outages will not begin to materialize until approximately REDACTED, as shown in Figure I.7 below. The figure shows (a)

21

a trend of historical unit outages under various cold weather conditions (see Appendix A for more detailed explanation of this trend), (b) an incremental trend of these outages assuming a REDACTED underlying system "EFOR", and (c) a trend representing the assumptions used in this study that includes expected performance improvements.
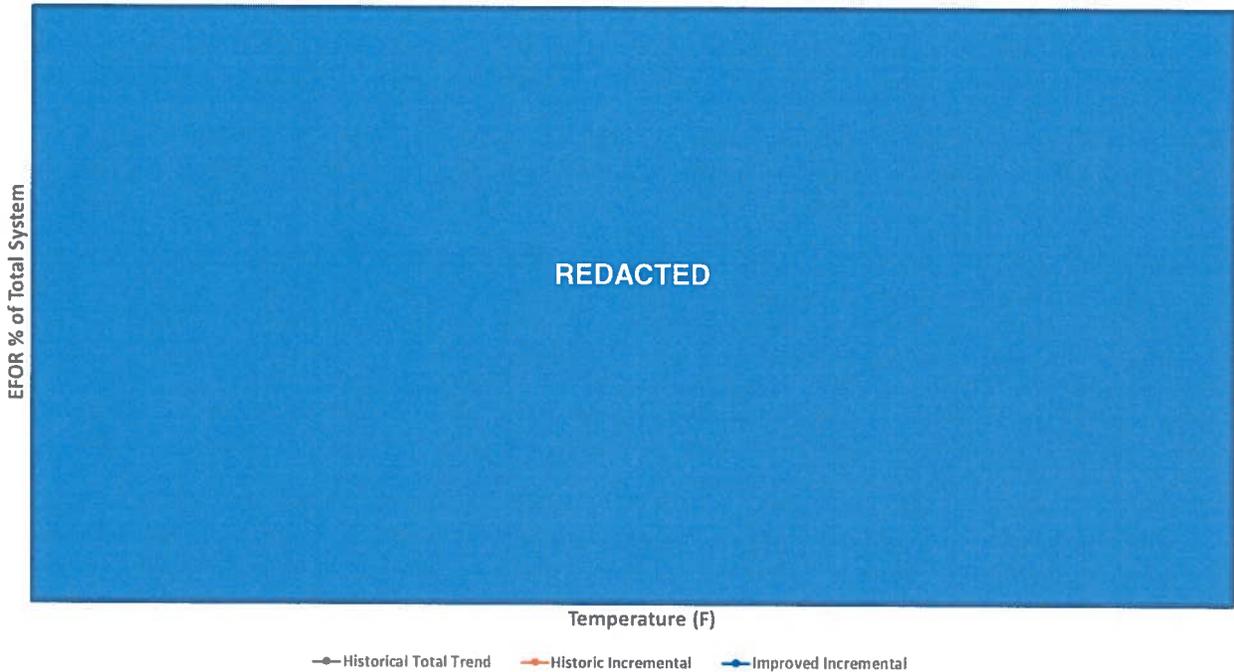
Figure I.7. Cold Weather Outage Assumptions

I. Planned Outage Patterns

Planned outages occur most often in the shoulder months because the demand on the units to run during the peak demand months does not allow for a lot of down time. Traditionally, planned maintenance events are not scheduled during either the summer months (June-September) or January and February unless it cannot otherwise be avoided or for oil units in noncompliance zones. While maintenance schedules are generated annually for the upcoming 5 years, the Reserve Margin Study is looking more generically and therefore allows the model to schedule maintenance around anticipated peak load periods. The model schedules these maintenance outages during low demand periods in such a way that the maintenance outage rate achieves the desired rate for the year. In

Southern Company

general, this results in planned maintenance modeled relatively consistent with actual practice. Figure I.8 below shows the likelihood that a resource will be assigned a planned outage in any given month.
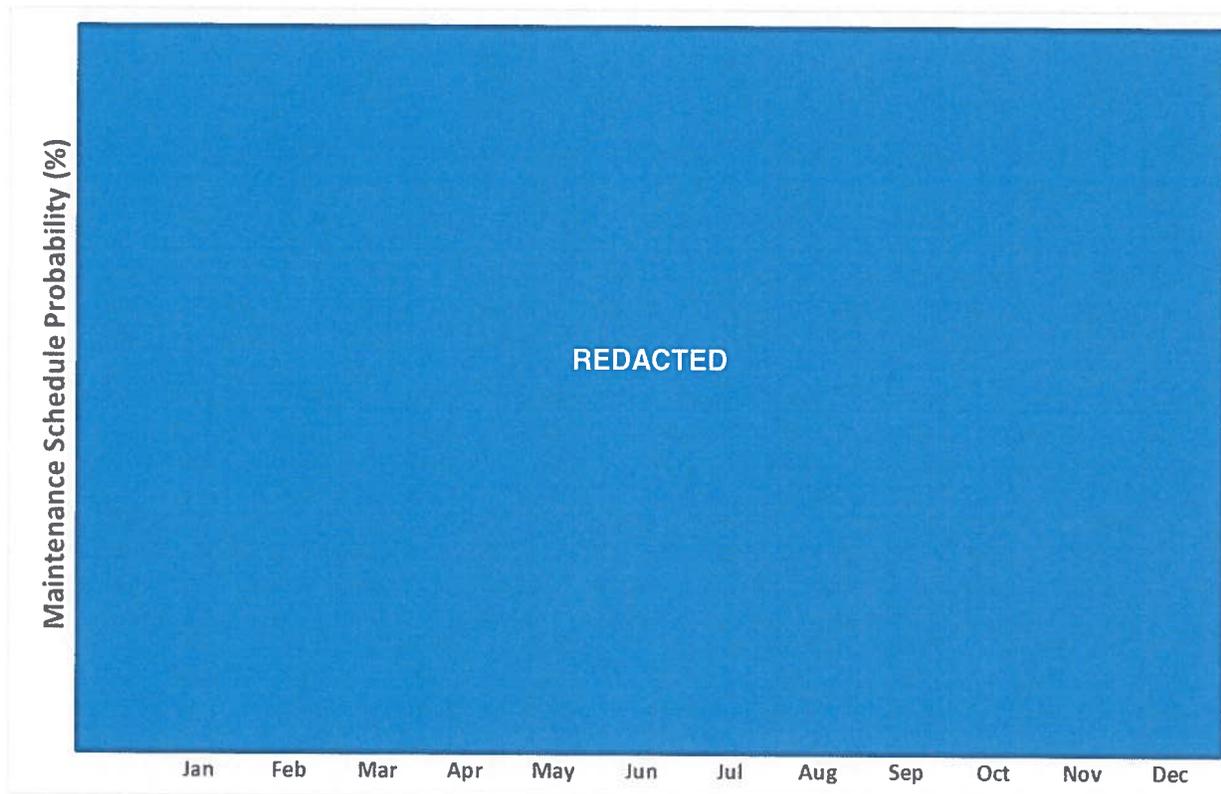
Figure I.8. Planned Outage Probability by Month

J. Commitment and Operating Reserves

Resources are committed to match current operating practices. Each week during a simulation, the loads for each hour of the week are examined and the optimum dispatch is set to meet the system peak load while maintaining the required operating reserves for every hour. The optimum dispatch takes into consideration which units are available, the minimum uptimes and downtimes for each unit, the startup costs and times for each unit, and the necessary required operating reserves. Operating reserves are required by the Southern Balancing Authority, which is the entity responsible for balancing load and generation in the region, to meet North American Electric Reliability Corporation ("NERC") Reliability Standards. The Southern Balancing Authority provides guidance regarding the amount of operating reserves that should be modeled based on their operational requirements. That

Southern Company

guidance included a total operating reserve requirement of REDACTED, broken down according to the following components:

- Regulating Reserves: REDACTED of nominal solar capacity or REDACTED
- Contingency Reserve-Spinning: REDACTED
- Contingency Reserve-Supplemental (or Non-Spinning): REDACTED

In addition, the Southern Balancing Authority's guidance established a firm load curtailment threshold of REDACTED of total operating reserves, meaning that firm load should be curtailed to maintain a minimum total operating reserve requirement of REDACTED. However, SERVM cannot model a fixed MW operating reserve value for the purposes of firm load curtailment. Rather, SERVM can be configured to curtail firm load to maintain Regulating Reserves plus Contingency Reserve-Spinning. Therefore, only 496MW of Contingency Reserve-Spinning was modeled so that the sum of Regulating Reserve and Contingency Reserve-Spinning did not exceed REDACTED. The remaining REDACTED of the REDACTED of operating reserves was modeled as Contingency Reserve-Supplemental, such that the final modeled operating reserves were as follows:

- Regulating Reserves: REDACTED
- Contingency Reserve-Spinning: REDACTED
- Contingency Reserve-Supplemental (or Non-Spinning): REDACTED.

K. Dispatch Order

Generation resources are generally dispatched economically based upon dispatch prices. The exceptions include energy-limited resources and non-dispatchable resources. Energy-limited resources, such as hydro and pumped storage hydro, are typically scheduled based on availability of water and expected system costs. Non-dispatchable resources, such as solar and wind vary with the weather. Therefore, the dispatchable resources are typically optimized around the output of these other non-dispatchable or pre-scheduled resources. Demand response resources either self-curtail based upon price (*e.g.*, Real Time Pricing programs) or are called whenever the system reaches certain reliability conditions (such as a system alert). Figure I.9 below shows the dispatch stack order for the dispatchable resources modeled in the 2018 Reserve Margin Study. The chart excludes the energy-limited, non-dispatchable, and demand response resources.

Southern Company
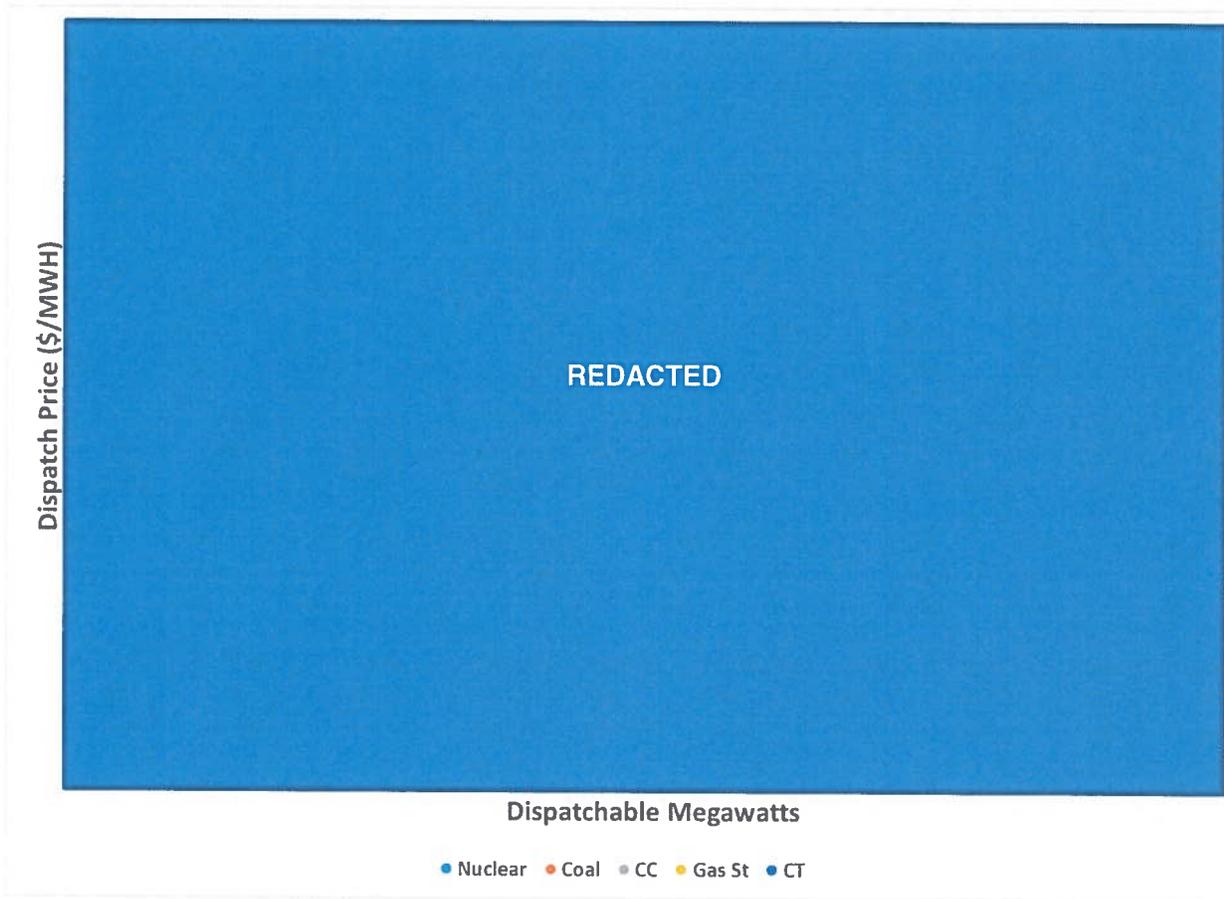
Figure I.9. System Dispatch Stack

L. Dispatchers' Peak Load Estimate Error

The dispatchers' peak load estimate error consists of three separate time periods, including day ahead, four-hour ahead, and hour ahead. The amount of dispatcher's peak load estimate error modeled for each of these time periods was based on actual, historical forecast error data for the years 2012 through 2015. The table below shows the resulting mean and standard deviation that served as the basis for the modeled dispatcher's peak load estimate error.

Table I.9. Historical Dispatcher's Peak Load Forecast Error

	Day Ahead Mean	Day Ahead Std Dev	4-Hour Mean	4-Hour Std Dev	Hour Ahead Mean	Hour Ahead Std Dev
January	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Southern Company

February	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
March	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
April	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
May	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
June	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
July	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
August	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
September	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
October	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
November	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
December	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

M. System-Owned Conventional Hydro Generation

System-owned hydro capacity of 2,400 MW (projected for the year 2025) was divided into two components:

1) Scheduled Hydro
2) Emergency or "Unloaded" Hydro

This study includes 54 different hydro scenarios that are matched with the 54 weather scenarios. The 54 scenarios chosen are based on the past 54 years (1962-2015) of weather and hydro data. For each of the scenarios, scheduled hydro capacity is modeled based on actual history.

The optimal dispatch of hydro resources is not solely an economic decision. Planners must consider river flow requirements and impacts on other reservoirs in the same river system. During drought conditions, it is rare that the full capacity of all hydro resources would be dispatched at the same time. The total hydro capacity that is not used as part of the daily schedule would be available as emergency hydro. Only in cases of extreme need is the emergency hydro capacity called upon to operate. Also, the emergency hydro block is only available for a small number of events per year. To model this within SERVM, the emergency hydro block is tied to a flex energy account to reflect the limited availability of this emergency hydro energy. If the emergency hydro capacity is needed to meet load during emergencies, the model will pull energy from this account. If the energy account becomes depleted, the capacity will not be available during subsequent emergencies.

Southern Company

Figure I.10 depicts the monthly energy produced by the two components of System-owned hydro generation in a representative year, 1998. The figure illustrates the typical distribution of available hydro energy across the months of the year.
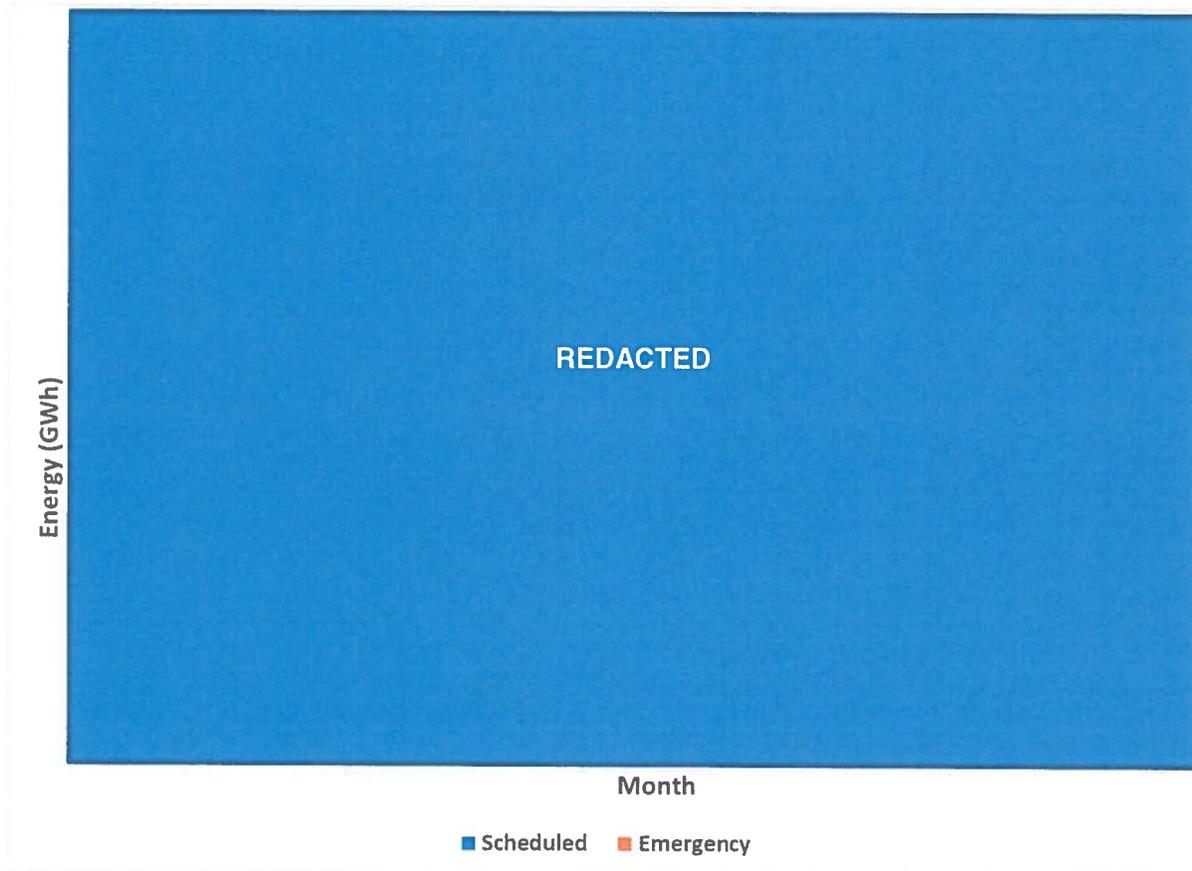
Figure I.10. Hydro Energy Availability (1998 Example Data)

As with the weather data, the availability of hydro energy can vary year to year. Figure I.11 below illustrates the total available scheduled hydro energies from the past 54 weather years (1962-2015).

Southern Company
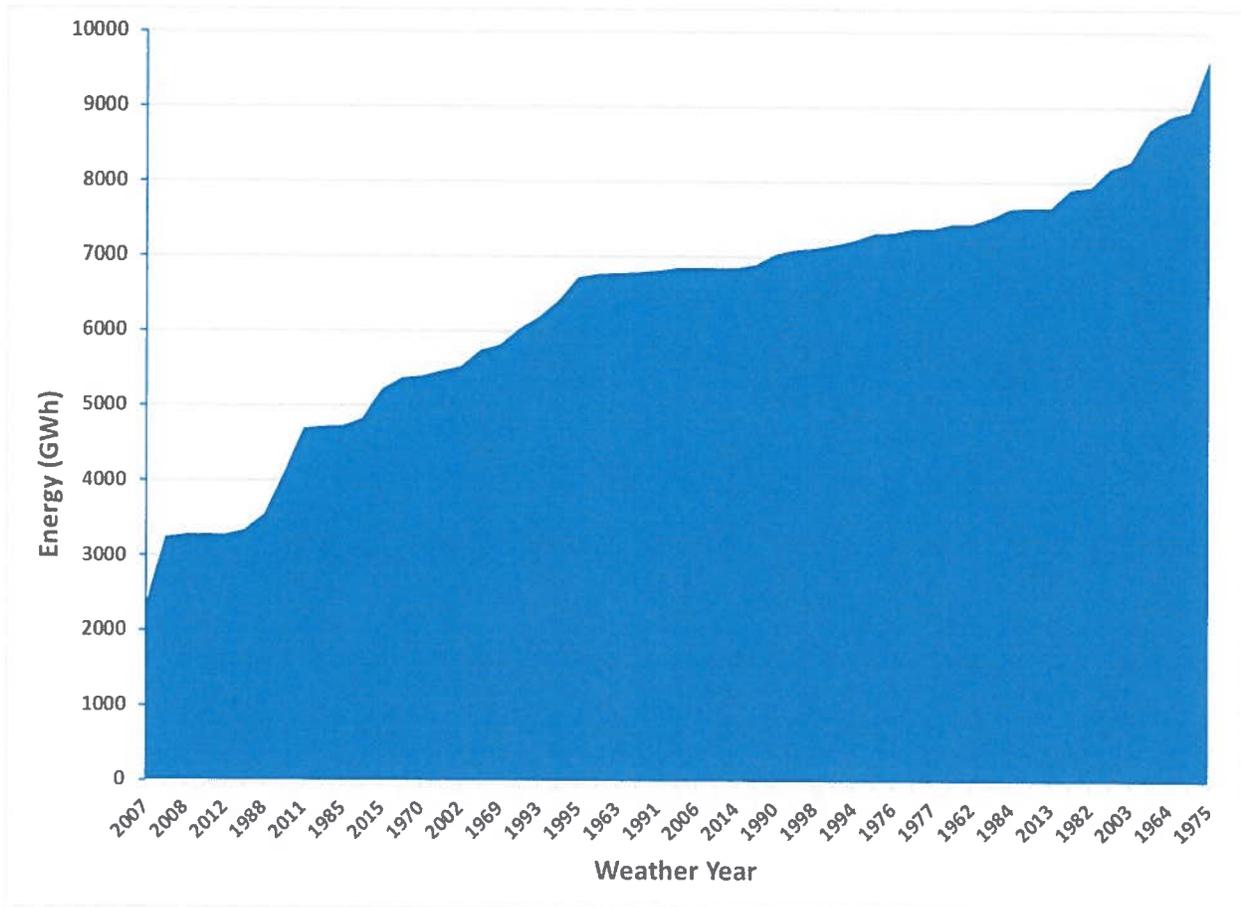
Figure I.11. Annual Scheduled Hydro Energies

N. SEPA Conventional Hydro

The Southeastern Power Administration ("SEPA") conventional hydro is less flexible in its operation than the System-owned hydro. The System has a contractual right to an allocation of the SEPA hydro capacity. Within SERVM, SEPA conventional hydro is modeled as a standard hydro unit with minimum daily dispatches. As currently modeled, the System is entitled to 477 MW taken over four hours per weekday, with a minimum daily schedule of 637.8 MWh and a maximum monthly energy allocation of 14.162 GWh.

Southern Company

O. Pumped Storage Hydro

Pumped storage hydro is a resource that is designed to pump water to an elevated reservoir using energy at off-peak periods when prices are low, and to generate electricity by releasing that water at times when prices are high. The dispatch of pumped storage is not simply a reliability decision, although the reservoir should always be kept at a level where energy will be available for emergency conditions. The System has a total of 540 MW of pumped storage resources spread across two different locations (Wallace Dam and Rocky Mountain Pumped Storage Facility). The Rocky Mountain Pumped Storage Facility is co-owned with Oglethorpe Power Corporation ("OPC").

P. Demand Response Resources

Approximately REDACTED of DRR capacity (contract value) is included in the analysis for the summer, and approximately REDACTED are included for the winter. These DRR include such programs as Interruptible Service ("IS"), Real-Time Pricing ("RTP"), Direct Load Control ("DLC"), Conservation Voltage Reduction ("CVR"), and Stand-by Generation ("SBG"). The model reflects both the seasonal availability as well as the contract constraints (*e.g.,* hours per year, days per week, and hours per day) for these energy-limited resources, so there is no need to adjust the contracts in the model by multiplying by Incremental Capacity Equivalent ("ICE") factors. In general, ICE factors represent the worth of load management resources, such as an interruptible service contract, relative to the value of incremental generating capacity that can be added to the system.

These resources occupy specific positions in the dispatch order as established by an assumed dispatch price. The position in dispatch affects their ability to reduce EUE and alters the frequency with which they are called. Some of these resources, such as RTP, are called based on economics and have an assumed dispatch price associated with them that is consistent with the expectation of the market prices that would result in self-curtailment by the customer. Others are called only to avoid EUE, and their assumed dispatch price is used mainly to establish the priority in which these programs are called. That priority is established based on how operations would anticipate them to be called in a generation shortfall event and would result in CVR being called first, followed by DLC, then IS, and finally SBG. Within the IS category, the programs are split into three blocks so that not all contracts are called simultaneously.

29

Southern Company

Q. Renewable Resources

NOTE: Except as otherwise stated, the Southern Companies maintain the right to use the electricity and all environmental attributes associated with all renewable projects discussed in this report for the benefit of its customers. This includes the right to use the electricity and the environmental attributes for the service of customers, as well as the right to sell environmental attributes, separately or bundled with electricity, to third parties.

The amount of renewable resources modeled for the System includes

- Biomass: 248 MW
- Landfill Gas: 43 MW
- Solar: 3,144 MW, and
- Wind: 588 MW.[11]

Biomass and landfill gas resources were modeled like other resources with a fixed output level based on their nominal capacity. However, the output of wind and solar resources are dependent upon weather conditions and location. Except for a few of the wind resources on the System that have been contracted based on a fixed hour-by-hour schedule, the output of the wind and solar resources varies moment-by-moment, hour-by-hour, and year-by-year. These wind and solar resources have been modeled with 8,760-hour profiles that are consistent with each of the 54 weather years as well as consistent with their location. Because the profiles included in the model for these resources reflect the hour-over-hour and year-over-year variances in output, there is no need to adjust the resources by multiplying by ICE factors.

R. Natural Gas Availability

Natural Gas operates in accordance to the Gas Day (*i.e.*, 9AM-9AM), whereas electricity operates according to the Electric Day (*i.e.*, Midnight to Midnight). Firm gas transportation is procured for the fleet's gas-fired units, but 24-hour Gas Day coverage is not procured for every plant. The amounts to be procured are generally driven by the System's Fuel Policy. Although case-specific situations may

---

[11] Wind capacity listed includes certain fixed delivery wind energy contracts. The total wind capacity shown includes the amounts delivered from these contracts coincident with the System peak.

Southern Company

allow for deviations from the Fuel Policy, for purposes of the 2018 Reserve Margin Study, all facilities under control of the Operating Companies were modeled in compliance with the Fuel Policy unless they had no contractual rights to dictate the amount of gas transportation to be purchased for the facility.

SERVM models both firm and non-firm gas transportation and its associated availability. During periods of high demand for natural gas, the System is limited to firm transportation contracts since interruptible transportation is not available. This constraint has been incorporated into the modeling process. The model begins phasing out interruptible transportation (*i.e.*, it starts becoming unavailable) when the daily minimum system weighted temperature falls below REDACTED or when the daily maximum system weighted temperatures rises above REDACTED. When the daily minimum temperature falls below REDACTED or the daily maximum temperature rises above REDACTED, no interruptible transportation is available for that Gas Day. Figure I.12 below illustrates the availability of interruptible transportation as modeled within SERVM.

Temperature (F)
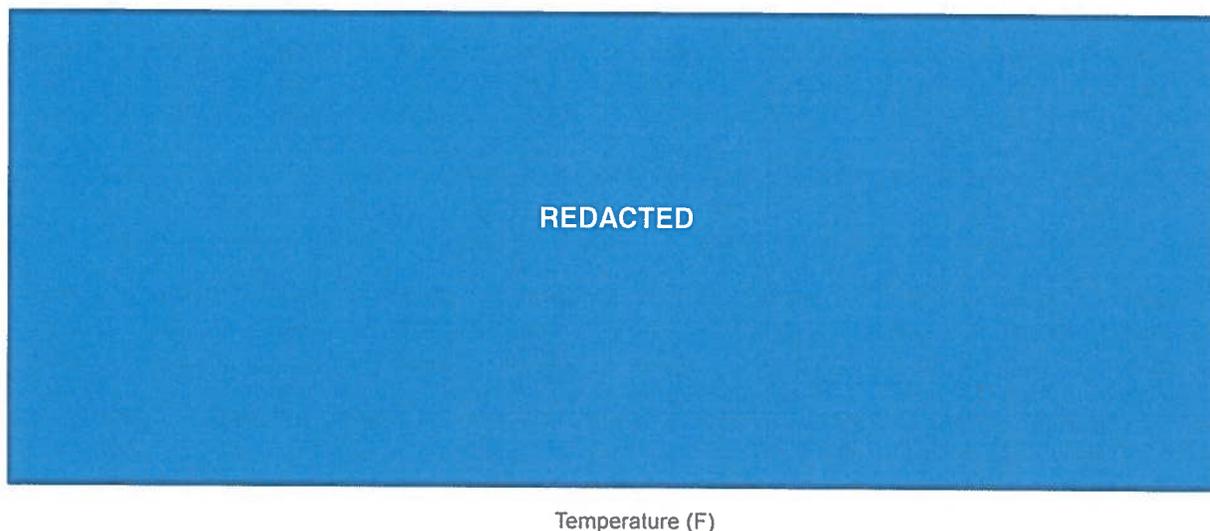
Figure I.12. Interruptible Gas Transportation Availability Model

Southern Company

S. Oil Availability

For dual-fuel (gas/oil) and oil-fired units, oil availability is dependent upon onsite storage. Storage capacity is limited, so when gas is not available, onsite oil supply will deplete quickly. This may limit a unit's availability if refilling efforts cannot keep up with usage.

T. Capacity Cost

For the type of analysis performed in this study where the objective is to balance the cost of the incremental capacity with the reliability benefits achieved by that capacity addition, it is necessary that the capacity considered represents a true reliability addition, not an addition for both reliability and energy economics. As such, simple-cycle CT technologies are the appropriate resources to be utilized for the evaluation. Therefore, the cost associated with advancing a CT one year is the cost of capacity used in the analysis. This cost is also known as the "economic carrying cost" or one-year deferral cost associated with that resource. Since both summer and winter evaluations were performed in the 2018 Reserve Margin Study, economic carrying costs based on both summer and winter performance characteristics were needed. The CT cost model is a green-field site of four dual-fueled units each with a 95°F ambient temperature summer rating of REDACTED and a 40°F ambient temperature winter rating of REDACTED, resulting in a summer performance economic carrying cost in 2025 dollars of REDACTED and a winter performance economic carrying cost in 2025 dollars of REDACTED.

U. Cost of Expected Unserved Energy

To estimate the cost of EUE, Freeman, Sullivan & Company conducted an outage cost survey of Georgia Power Company and Mississippi Power Company customers in 2011.[12] This survey was conducted among the following four customer classes:
- Residential;
- Commercial (below 1 MW average demand);
- Industrial (below 1 MW average demand); and
- Large business (commercial and industrial customers above 1 MW average demand).

---

[12] While the survey only included customers from two Operating Companies, the results are considered appropriate for all Operating Companies, and so the cost of the survey was shared by all Operating Companies.

Southern Company

The cost of EUE (in 2012$) for these four customer classes is shown in Table I.10 for both the summer and winter periods. The cost of EUE was then adjusted by the customer weighting factor representing recent relative weighting of customers in that class. The results of that weighting are also shown.

Table I.10. EUE Cost

EUE COST IN 2012 $					
Outage Scenario	Residential ($/kWh)	Commercial ($/kWh)	Industrial ($/kWh)	Large Business ($/kWh)	Weighted Average ($/kWh)
Weighting Factor (%)	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
1 hour, no warning, summer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Contribution to Weighted Average	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
1 hour, no warning, winter	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Contribution to Weighted Average	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

These estimated weighted costs of EUE were then escalated to 2025 dollars for use in the 2018 Reserve Margin Study. The result was a Value of Loss Load ("VOLL") of REDACTED for summer and REDACTED for winter.

Southern Company

II. SIMULATION PROCEDURE

A. Case Specification

The simulations performed for the 2018 Reserve Margin Study were designed to estimate System generation reliability across a wide range of weather conditions, LFEs, and reserve margins. Eleven discrete reserve margin levels were simulated to calculate the expected costs over a broad range of scenarios. Load shapes corresponding to the 108 weather datasets (54 weather years, each with Tuesday and Saturday start days), were run in combination with varying LFEs. Weather years were paired such that loads, hydro scenarios and renewable profiles were consistent. The simulation variables were as depicted in Table II.1.

Table II.1. SERVM Case Variables

Weather and Hydro Years	Summer/Winter Reserve Margins	LFEs
1962-2015	10%/17.0%	REDACTED
	11%/18.2%	REDACTED
	12%/19.5%	REDACTED
	13%/20.7%	REDACTED
	14%/21.9%	REDACTED
	15%/23.1%	REDACTED
	16%/24.4%	
	17%/25.6%	
	18%/26.8%	
	19%/28.0%	
	20%/29.3%	

The winter reserve margins are the equivalent of their summer counterparts. Thus, the winter reserve margins are not listed in whole percentage point increments.

Positive LFE represents an over forecasted load, meaning actual load was less than forecasted load.

Without accounting for load forecast uncertainty, the total number of combinations for the analysis would be 54 × 2 × 11, or 1,188 cases. Considering the six load forecast points yields 7,128 cases (54 × 2 × 11 × 6 cases). Each of these cases were then evaluated 100 different times, each with a different set of random forced outage draws on the generating resources, yielding 712,800 production cost simulations (54 x 2 x 11 x 6 x 100 cases). Estimating EUE for each of the 712,800 simulations provides sufficient data for regression analysis of other combinations not specifically simulated. This

Southern Company

set of simulations was performed for both the traditional analysis as well as the winter focus analysis and the summer focus analysis.

B. Probabilities of Occurrence for Input Variables

As discussed in the previous sections, the chronological variable inputs into the model are used to represent appropriate ranges of data. For example, the weather years selected to exemplify load variations due to temperature changes represent 54 years of historical data. This is also true for the hydro patterns and solar profiles developed. Each, however were modeled twice – once with a Saturday start and once with a Tuesday start – resulting in 108 different weather/hydro datasets. The implementation of load forecast uncertainty into the evaluation is representative of the potential (supported by historical information) LFEs when considering the future. Each of the six forecast errors has its own probability of occurrence that is related to the probability of error in forecasted economic indicators. For each reserve margin studied, the combined set of input variables results in 648 individual cases having their own designated probability of occurrence to be used in the probabilistic evaluation. Table II.2 depicts the probabilities assigned to each of these variables and the resulting probability for each case. This total case probability is determined by combining the probabilities of the determinant variables. The weather years and start days all have equal probability of occurrence.

Table II.2. Simulation Case Probability

LFE	LFE Probability	Weather/Hydro Probability	Start Days Probability	Total Case Probability
REDACTED	0.0952	0.018519	0.5	0.000882
REDACTED	0.1429	0.018519	0.5	0.001323
REDACTED	0.2381	0.018519	0.5	0.002205
REDACTED	0.3333	0.018519	0.5	0.003086
REDACTED	0.1429	0.018519	0.5	0.001323
REDACTED	0.0476	0.018519	0.5	0.000441

C. Reliability Model Simulations

SERVM incorporates Monte Carlo techniques to conduct generation reliability simulations. Monte Carlo analysis uses a random number generator to determine generating unit availability for the System. For each iteration, the model simulations will randomly select the state of a generating unit as fully operational, partially failed, or completely failed and determine if the system experiences loss of load and associated EUE.

Southern Company

For each of the 648 cases, each hour of the year was modeled with 100 draws from the distribution of generating unit outage and duration data to determine if there exists a deficiency of generating capacity to meet load demand. The 100 iterations were averaged together to establish a case-specific result. A deficiency of generating capacity in any hour is recorded as a loss of load hour. The magnitude of the outage during that hour is measured by EUE. The EUE is then aggregated by month and multiplied by the respective value of lost load for that month to determine the EUE cost. The monthly EUE costs are then summed together for the year to determine EUE cost for that case. The case EUE cost is then multiplied by the probability of occurrence for that case and the results for all cases are summed to determine the expected value of EUE cost for that reserve margin simulation. This process is repeated to determine the expected value of generation costs, import costs, emergency purchase (or sales) costs, the cost of non-firm outages (i.e., demand response costs), and costs associated with non-spinning reserve shortfalls.

For each reserve margin simulation, the expected value of generation costs and import costs are then summed together to establish "Production Cost". Likewise, the expected value of emergency purchases (or sales), demand response costs, costs associated with non-spinning reserve shortfalls, and EUE costs are summed together to establish "Reliability Cost." Figure II.1 shows the formula used for calculating EUE. Other components are calculated similarly.

$$Expected\ Y = \sum_{i=1}^{n}(Y_i * Probability_i)$$

where

$Y = EUE\ and,$

$n = number\ of\ cases$

Figure II.1 Variable Calculation Formula

Table II.3 thru Table II.6 provide an example of implementing the formula for a sample data set containing the 10 worst Reliability Cost cases. Table II.3 shows the Reliability Cost components with their per unit weighted costs. Table II.4 shows the probability weighting of the Total Reliability Cost. For illustrative purposes, all calculations are for a 17% summer reserve margin simulation.

Southern Company

Table II.3. Sample Calculation Top 10 Worst Reliability Costs at 17% Summer Reserves

Data Set	Emergency Purchases (MWh)	Emergency Purchases Cost ($/MWH)	EUE (MWh)	EUE Cost ($/MWH)	Demand Response Calls (MWh)	Weighted DR Cost ($/MWH)	Loss of Non-Spin Reserve (MWh)	Loss of Non-Spin Cost ($/MWH)
1	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
3	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
4	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
5	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
6	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
7	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
8	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
9	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
10	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Table II.4. Worst Reliability Costs Weighted Probability

Data Set	Probability	Emergency Purchases ($M)	EUE ($M)	Demand Response Calls ($M)	Loss of Non-Spin ($M)	Total Reliability Cost ($M)	Weighted Reliability Cost ($M)
1	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
3	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
4	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
5	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Southern Company

6	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
7	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
8	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
9	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
10	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

A similar calculation is performed for the components of Production Cost as demonstrated in Table II.5 and Table II.6 for the same 10 cases shown above.

Table II.5. Production Cost Components for Sample Data Set

Data Set	Generation Costs ($M)	Purchases (MWh)	Purchase Cost ($/MWH)
1	REDACTED	REDACTED	REDACTED
2	REDACTED	REDACTED	REDACTED
3	REDACTED	REDACTED	REDACTED
4	REDACTED	REDACTED	REDACTED
5	REDACTED	REDACTED	REDACTED
6	REDACTED	REDACTED	REDACTED
7	REDACTED	REDACTED	REDACTED
8	REDACTED	REDACTED	REDACTED
9	REDACTED	REDACTED	REDACTED
10	REDACTED	REDACTED	REDACTED

Table II.6. Production Cost Weighted Probability

Data Set	Probability	Generation Costs ($M)	Purchase Cost ($M)	Total Production Cost ($M)	Weighted Total Production Cost ($M)
1	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
3	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
4	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Southern Company

5	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
6	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
7	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
8	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
9	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
10	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

By applying regression analysis to the expected values of Production Cost and Reliability Cost, a curve summarizing the Production Cost, Reliability Cost, and Incremental Capacity Cost as a function of reserve margin was developed. These results are discussed in detail in the next section.

Southern Company

III. BASE CASE RESULTS

A. Traditional Study Results

In theory, the economic optimum reserve margin, or the EORM, should be the reserve margin that results in the minimum total system costs. The three components of total system costs (Production Cost, Reliability Cost, and Incremental Capacity Cost) that vary across reserve margin levels were added together to create an aggregate total system cost curve (the "U-Curve"). The minimum point on the resultant U-Curve, which is at 15.25%, represents the EORM. This graph is presented below.

REDACTED
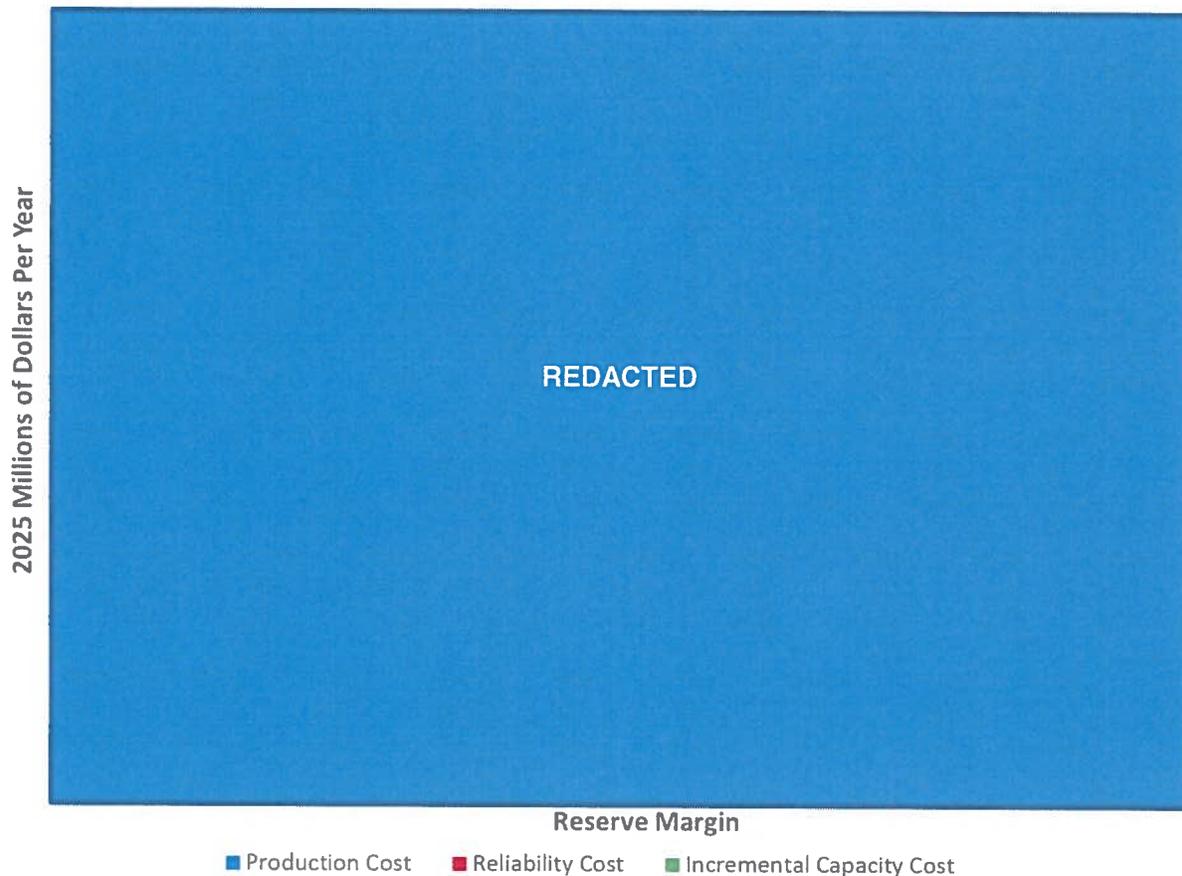
Figure III.1. Traditional EORM U-Curve

Southern Company

B. Winter-Focused Reserve Margin Results

The 2015 Reserve Margin Study identified several drivers associated with issues during extreme cold weather. Those drivers included:

a. the narrowing of summer and winter weather-normal peak loads,
b. the distribution of peak loads relative to the norm,
c. cold-weather-related unit outages,
d. the penetration of solar resources, and
e. increased reliance on natural gas.

In addition to these same drivers, the 2018 Reserve Margin Study identified an additional constraint – the availability of market purchases (see Assumptions section of this report). Because all these drivers will impact winter reliability, it has been determined that even though the System remains a summer peaking utility for the time being, the System's primary reliability risk is in the winter, resulting in the need for a Winter TRM. Appendix A addresses this need for a Winter TRM more thoroughly, but as an example of this need, Figure III.2 below shows seasonal EUE by reserve margin. As indicated by the chart, at low reserve margins, summer and winter have relatively equal expectations of EUE – with summer being higher at very low reserve margins. However, as reserve margins increase, the expectation of EUE in the summer reduces drastically. Similarly, the expectation of EUE in the winter falls as reserve margin increases, but not as drastically and even at 20% reserve margin, there is still a significant expectation of potential loss of load.

Southern Company
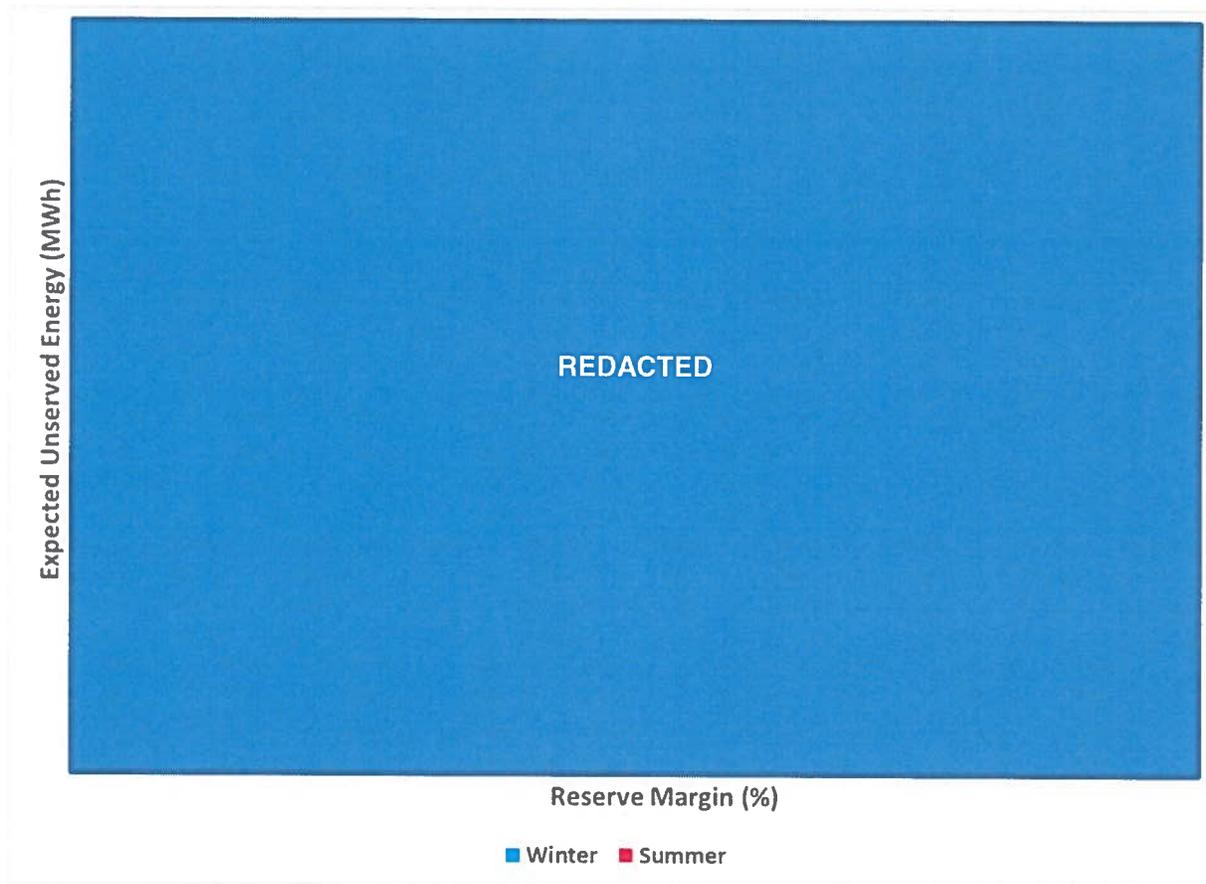
Figure III.2. Seasonal EUE by Reserve Margin

To address this winter reliability risk, a Winter TRM is necessary. Therefore, a separate analysis was performed where the focus of the study was on a winter reserve margin. Traditionally, the reserve margin is stated in summer terms – that is, stated in terms of summer peak loads and summer resource ratings. For example, the reserve margins in Figure III.2 above are all stated in summer terms. The traditional analysis is performed by developing the 108 historical weather load shapes in such a way as to ensure the average summer peak load from all 108 load shapes equals the summer peak demand forecast for the study year. To perform the winter focused reserve margin analysis, the 108 load shapes were adjusted such that the average of the winter peak loads equaled the winter peak demand forecast. The results of the study were then stated in winter reserve margin terms rather than summer reserve margin terms (i.e., stated in terms of winter peak loads and winter resource ratings). The minimum point on the resulting U-Curve was established as 22.5% as shown in the graph below.

Southern Company
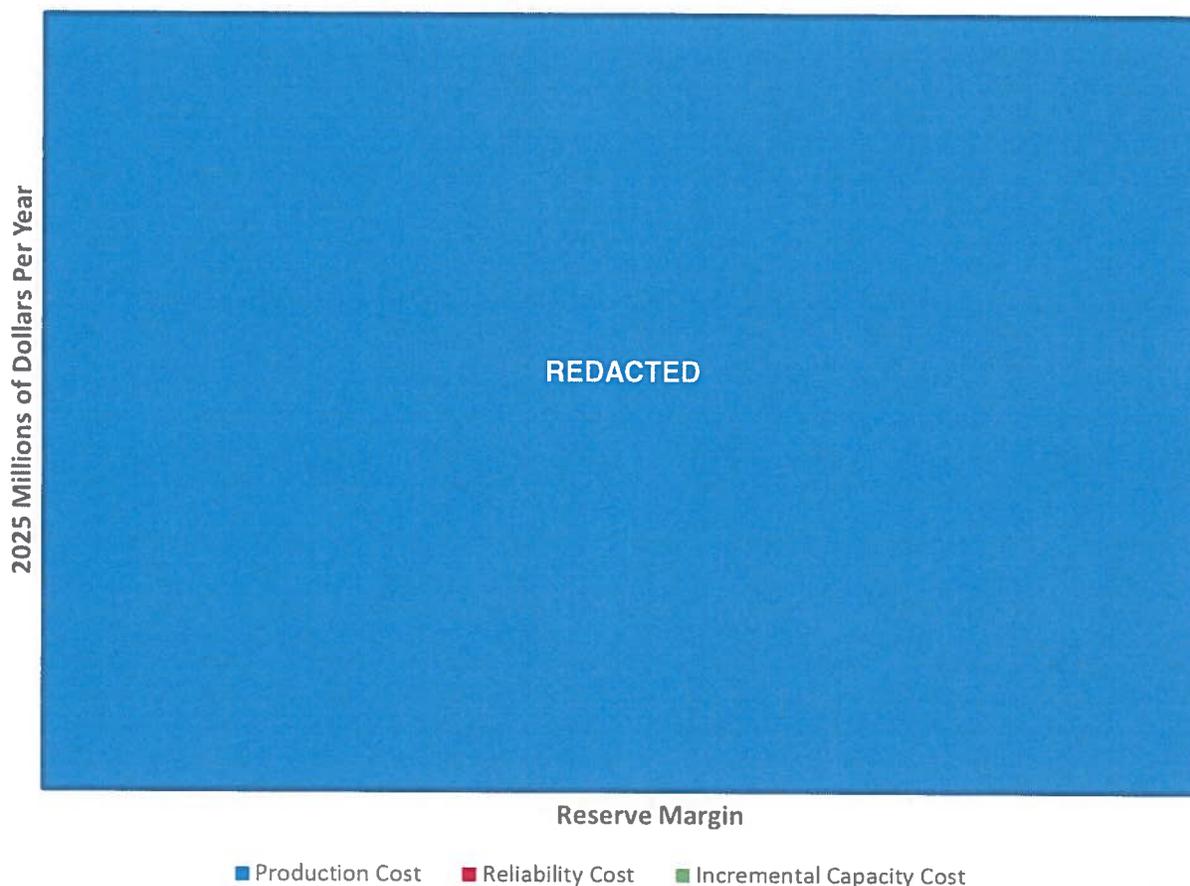
Figure III.3. Winter EORM U-Curve

It is important to recognize that while the EORM from the winter U-Curve occurs at a reserve margin that appears to be significantly higher than the EORM from the traditional, summer-oriented U-Curve, the EORM from the two cases represent similar levels of reliability and cost for the same underlying system. Each study contains a full year of hourly production cost simulations which inherently reflect 8,760 reserve margin levels. Therefore, the difference in absolute value (22.5% versus 15.25%) is primarily a function of stated terms, with the summer EORM being stated in terms of summer capacity ratings and the summer weather-normal peak load and the winter EORM being stated in terms of winter capacity ratings and winter weather-normal peak load.

C. Summer-Focused Reserve Margin Results

Given that the System's primary reliability risk is in the winter, it is possible to determine a summer-focused reserve margin without consideration of some of the key winter drivers, specifically without

▲ Southern Company

the incremental cold-weather generation outages or the natural gas fuel constraints. The idea behind this analysis is to determine the corresponding Summer TRM once the Winter TRM has been established. The following graph shows that a summer-focused EORM without those key drivers would be 14%.
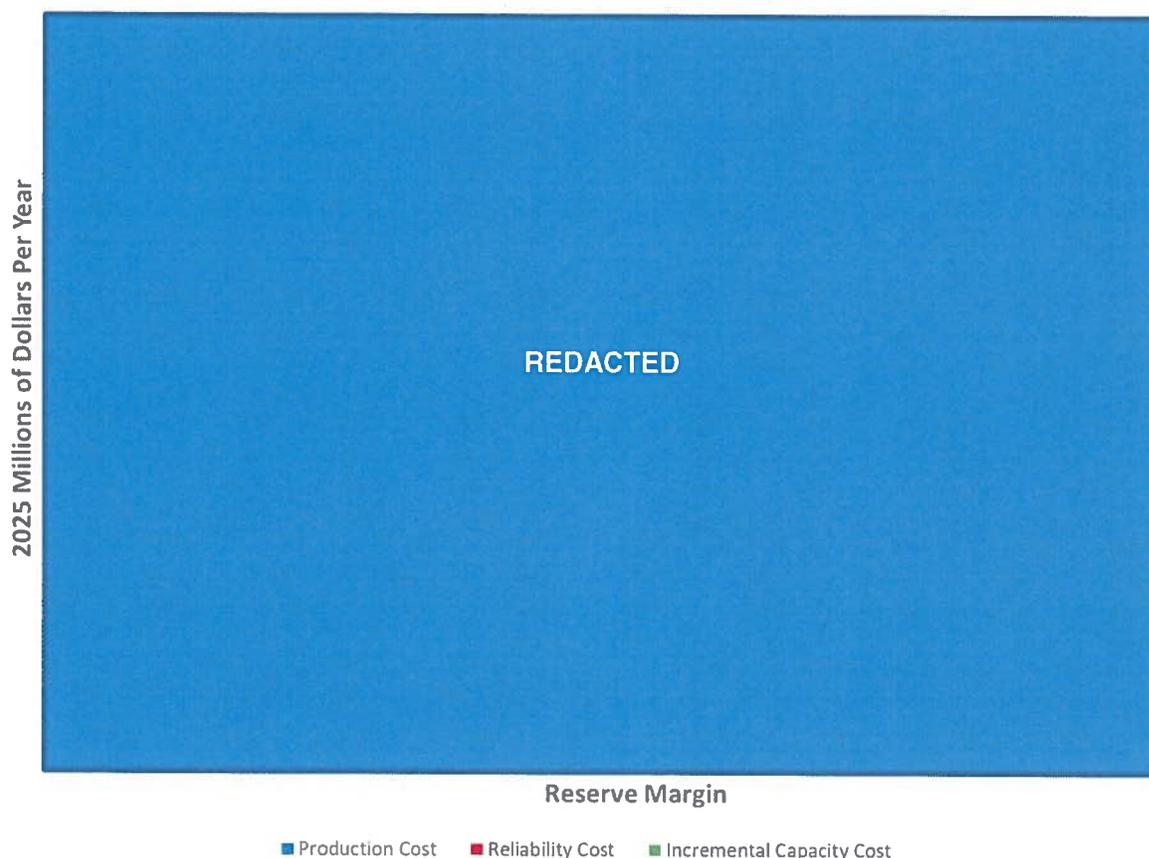
Figure III.4. Summer EORM U-Curve (Without Key Winter Drivers)

D. Risk Analysis

The winter-focused combination of Production Cost, Reliability Cost, and Incremental Capacity Cost results in a EORM of 22.5%. However, since Production Cost and Reliability Cost are highly dependent on the selected scenario, consideration of only the EORM does not give a complete picture. Figure III.5 illustrates the volatility in Production Cost and Reliability Cost exposure. In scenarios in which load grows faster than expected, temperatures are higher than expected, or unit performance is poorer than expected, the cost exposure can be much higher than the expected case.

Southern Company
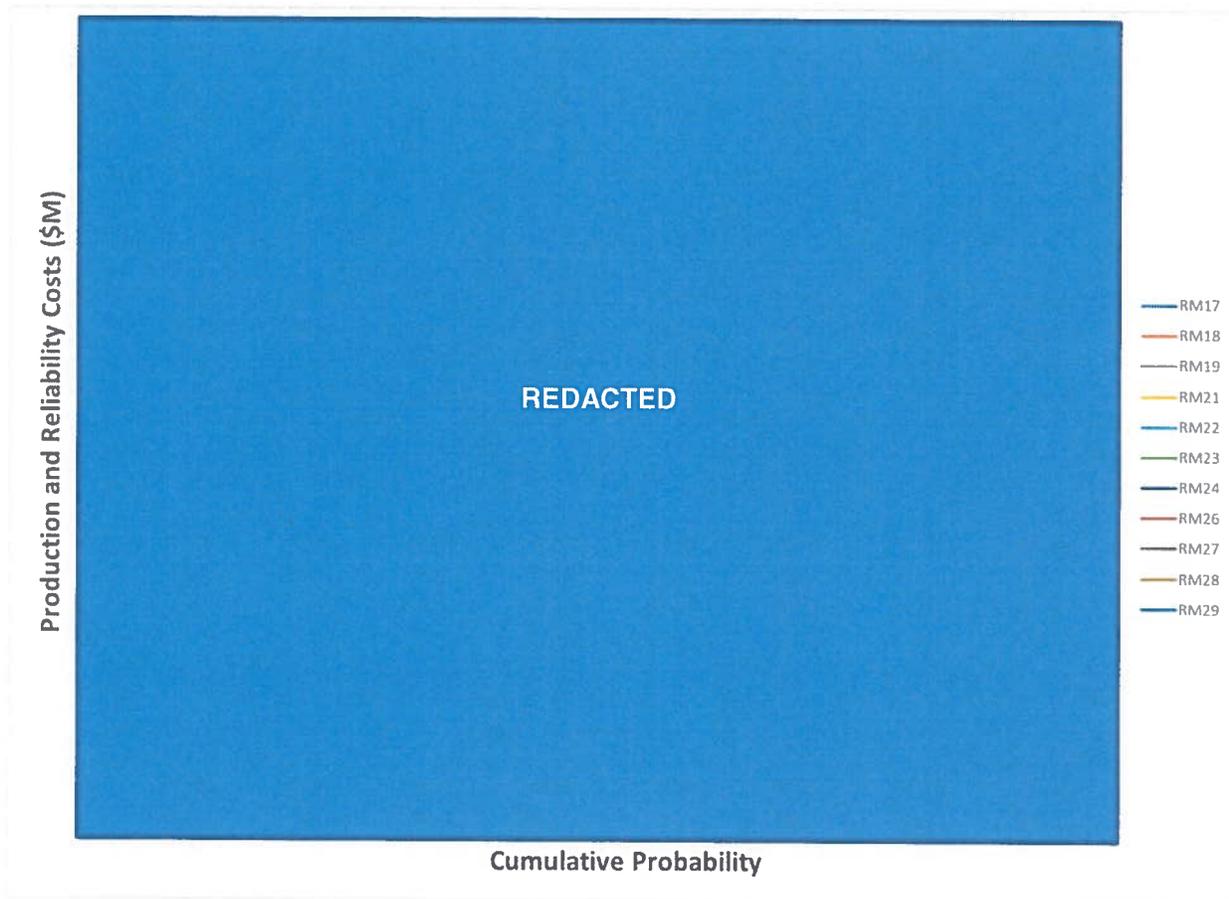
Figure III.5. Production and Reliability Cost Distributions for Winter Reserve Margins

Zooming in on the most extreme cases shown in Figure III.5 for each reserve margin further highlights the risk in carrying low reserves. Figure III.6 shows the exposure for the top 10% of all cases as ranked by Production Costs and EUE cost exposure. The most extreme case simulated at a 17% winter reserve margin shows over REDACTED per year in total exposure, while the most extreme case at a 26% reserve margin is approximately REDACTED.

Southern Company
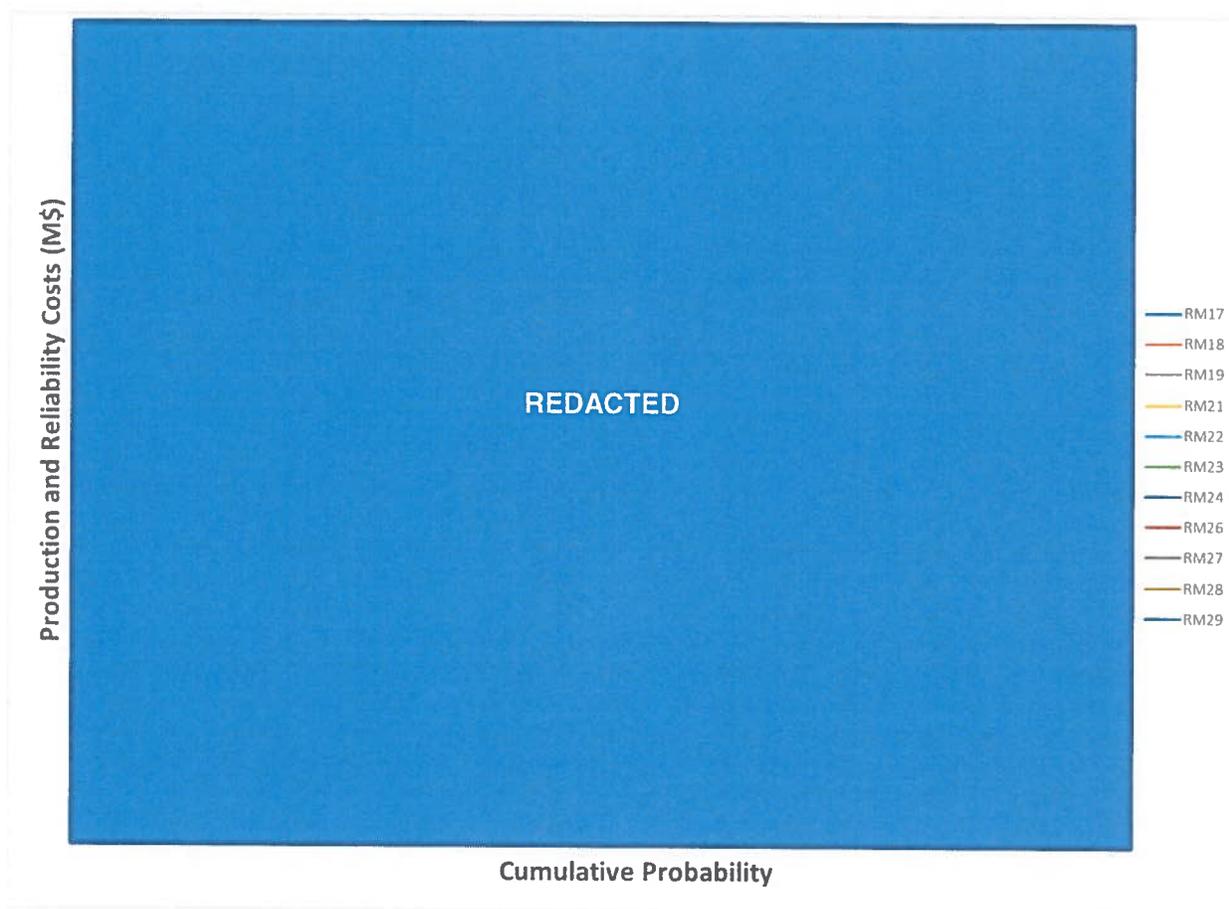
Figure III.6. Top 10% Distribution for Winter Reserve Margins

To more appropriately perform a comparison between highly volatile Production Costs and Reliability Costs and fixed Incremental Capacity Cost, thus protecting against the potential for an extremely high cost outcome, additional risk analyses should be performed. In the casualty insurance business, customers have the option of paying an insurance premium to cover the impact of a catastrophic loss. In this example, the annual insurance premium is higher than the cost of the loss times its probability. Customers and regulators are comfortable with paying an amount greater than the average loss because it makes the payments fixed. In the same way, utilities can procure capacity at fixed rates slightly above the EORM to prevent the possibility of certain high cost outcomes. The approach taken to evaluate the risk of these potential high cost outcomes and thus determine how much of an "insurance premium" to pay is to use a risk metric called Value at Risk ("VaR").

Southern Company

VaR is defined as the difference in cost at the expected value and the cost at some specified confidence interval (e.g., the 85th percentile of risk). The VaR accounts for the customers' exposure to higher costs above normal conditions. The VaR analysis looks at the incremental increase in expected cost to move from one reserve margin to the next reserve margin and compares that with the incremental decrease in VaR. So long as the incremental increase in expected cost is less than the incremental decrease in VaR, the premium (*i.e.*, the increased expected cost) is justifiable to protect against the potential high cost outcomes. The point at which the incremental increase in cost equals the incremental decrease in VaR represents the EORM at that confidence interval (as opposed to the EORM at the weighted average).

The table below illustrates the VaR at the 80th (VaR80), 85th (VaR85), 90th (VaR90), and 95th (VaR95) percentiles of confidence for a range of winter reserve margin targets.

Table III.1. Value at Risk

Reserve Margin	Expected Cost (M$)	VaR80 (M$)	VaR85 (M$)	VaR90 (M$)	VaR95 (M$)
22.00%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
22.25%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
22.50%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
22.75%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
23.00%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
23.25%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
23.50%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
23.75%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
24.00%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
24.25%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
24.50%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
24.75%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
25.00%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
25.25%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
25.50%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
25.75%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
26.00%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
26.25%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
26.50%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
26.75%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Southern Company

27.00%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
27.25%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
27.50%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
27.75%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
28.00%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
28.25%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
28.50%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
28.75%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
29.00%	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

For the 80th percentile of risk (VaR80), the incremental increase in expected cost roughly equals the incremental decrease in VaR80 when moving from 25.75% reserve margin to 26% reserve margin. At this point, the incremental increase in cost is REDACTED REDACTED REDACTED; and the decrease in VaR80, or decrease in customers' exposure to higher cost outcomes, is REDACTED REDACTED REDACTED REDACTED. Moving from 26% to 26.25% results in an increase in expected costs REDACTED REDACTED REDACTED that is greater than the decrease in VaR80 REDACTED REDACTED REDACTED. Thus, 26% represents the EORM at the 80th percentile of risk. Compared to the expected case TRM of 22.5%, a 26.0% reserve margin reduces the VaR80 exposure by REDACTED while only increasing the expected case cost by REDACTED. Higher confidence intervals were also examined. At the 85th percentile of risk, it would be justifiable to establish a reserve margin of 26.25%. At the 90th percentile of risk, it would be justifiable to establish a reserve margin of 27.25%. Likewise, at the 95th percentile of risk, it would be justifiable to establish a reserve margin of 28.5%. However, the increased expected cost for these three confidence intervals are REDACTED, REDACTED, and REDACTED, respectively. While justifiable from a cost/risk reduction perspective, the absolute increase in expected cost suggests use of the 80th or 85th confidence interval as there is a much bigger jump in expected costs moving to the 90th confidence interval.

Another way to explain and understand the risk analysis used in this study is to realize that the VaR analysis essentially establishes the EORM at the specified confidence interval. In other words, the Operating Companies calculate the EORM at the expected value of cost. However, because of risk, it would be justifiable to calculate the EORM at, for example, the 80th percentile of cost. This is precisely what the Var80 analysis accomplishes – the economic balance between cost and risk. Figure III.7 below shows the total cost (Production Cost plus Reliability Cost plus Incremental Capacity Cost) at

Southern Company

the 80th confidence interval. The resulting "U-Curve" confirms that the EORM at the 80th confidence interval is 26.0% - that is, 26.0% is the risk-adjusted EORM at the 80th confidence interval.
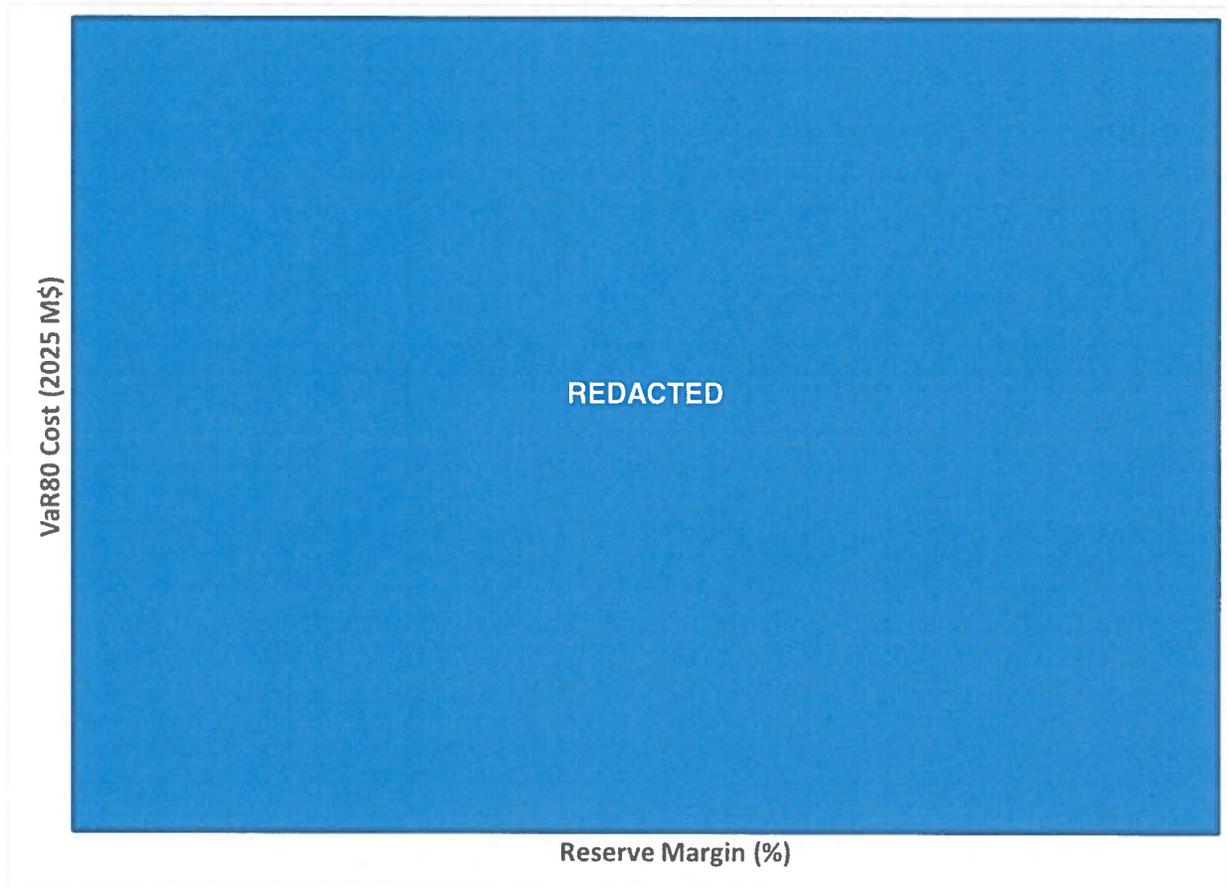
Figure III.7 80% Confidence Interval U-Curve

E. Loss of Load Expectation

Some regions throughout the country utilize Loss of Load Expectation (LOLE) as their primary resource adequacy reliability metric, while others either do not consider it or consider it as a secondary metric to the EORM. LOLE is the probabilistic count of the number of days in the study year in which the system experiences firm load shed of any duration. This metric does not measure the magnitude of the event and is relatively sensitive to several input assumptions. The most common business practice for those who use this metric is an LOLE value of 0.1 days per year, which is sometimes referred to as a one day in ten years (1:10 LOLE) reliability criterion. An LOLE of 0.1 days per year

Southern Company

presumes there is a 10% probability of a loss of load due to generation shortfall in any one year or an expectation that there would only be one loss of load event every 10 years.

Historically for the Southern Company System, this 1:10 LOLE threshold has occurred at reserve margins below the EORM. Thus, the primary focus has historically been on the risk-adjusted EORM to establish the TRM. However, as the Company continues to incorporate new reliability risks in its reliability modeling, more recent analyses have indicated that the LOLE for the System is much higher than previously expected. Thus, the reserve margin necessary to maintain the 1:10 LOLE threshold is also higher. Figure III.8 below illustrates how this metric looks for the System over the range of reserve margins studied for the 2018 Reserve Margin Study as compared to the 2012 and 2015 reserve margin studies. The reserve margins are shown in summer terms since neither the 2012 nor the 2015 studies included a winter analysis.
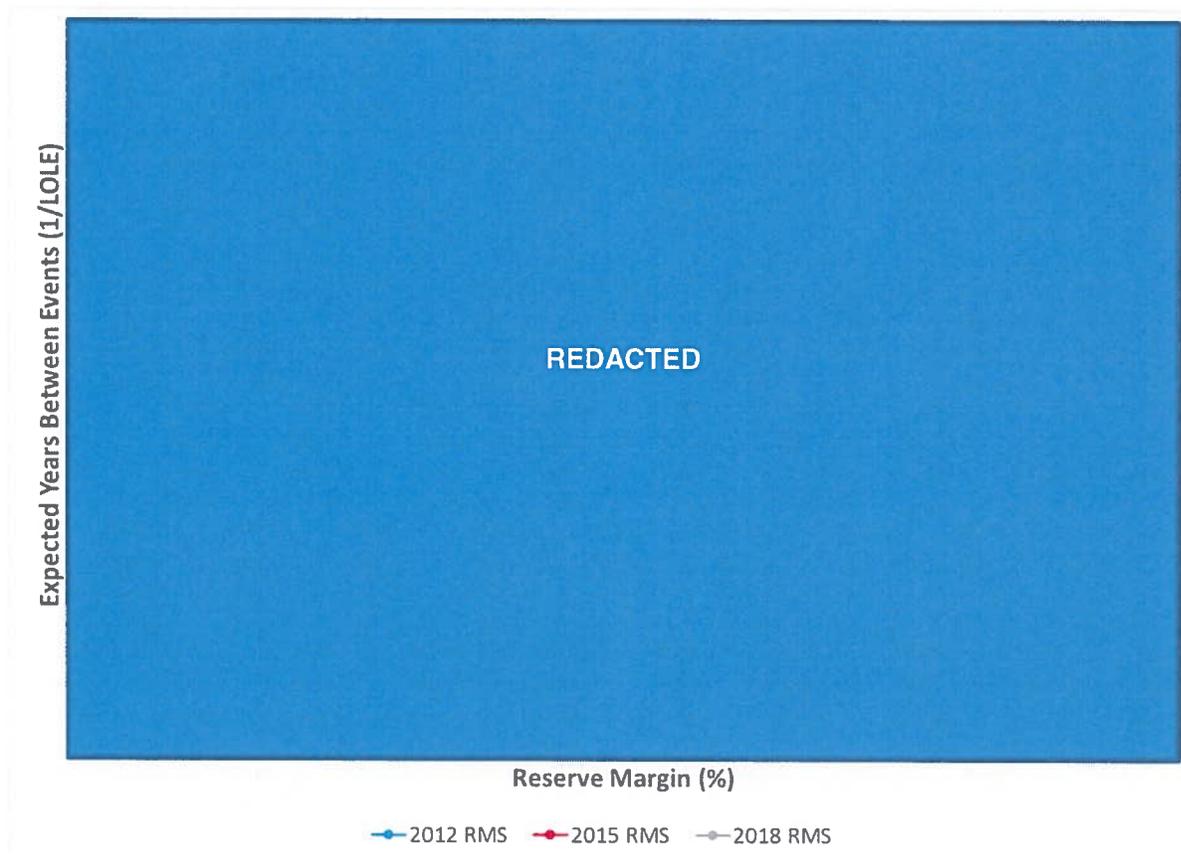
Figure III.8. Loss of Load Expectation by Summer Reserve Margin

Southern Company

At its current approved Target Reserve Margin of 16.25% (which is equivalent to a 24.7% winter reserve margin), the System has an LOLE of REDACTED or an expectation of one event in REDACTED REDACTED, which is below the 1:10 LOLE threshold. As indicated by the chart, to achieve a 1:10 LOLE threshold would require a 17% Summer TRM. Figure III.8 was shown in summer terms as a comparison to previous, traditional studies. However, since the increase in observed LOLE is associated with winter reliability issues, it is necessary to review these metrics as generated by the winter focus study. Figure III.9 below shows the LOLE for the winter reserve margins evaluated.
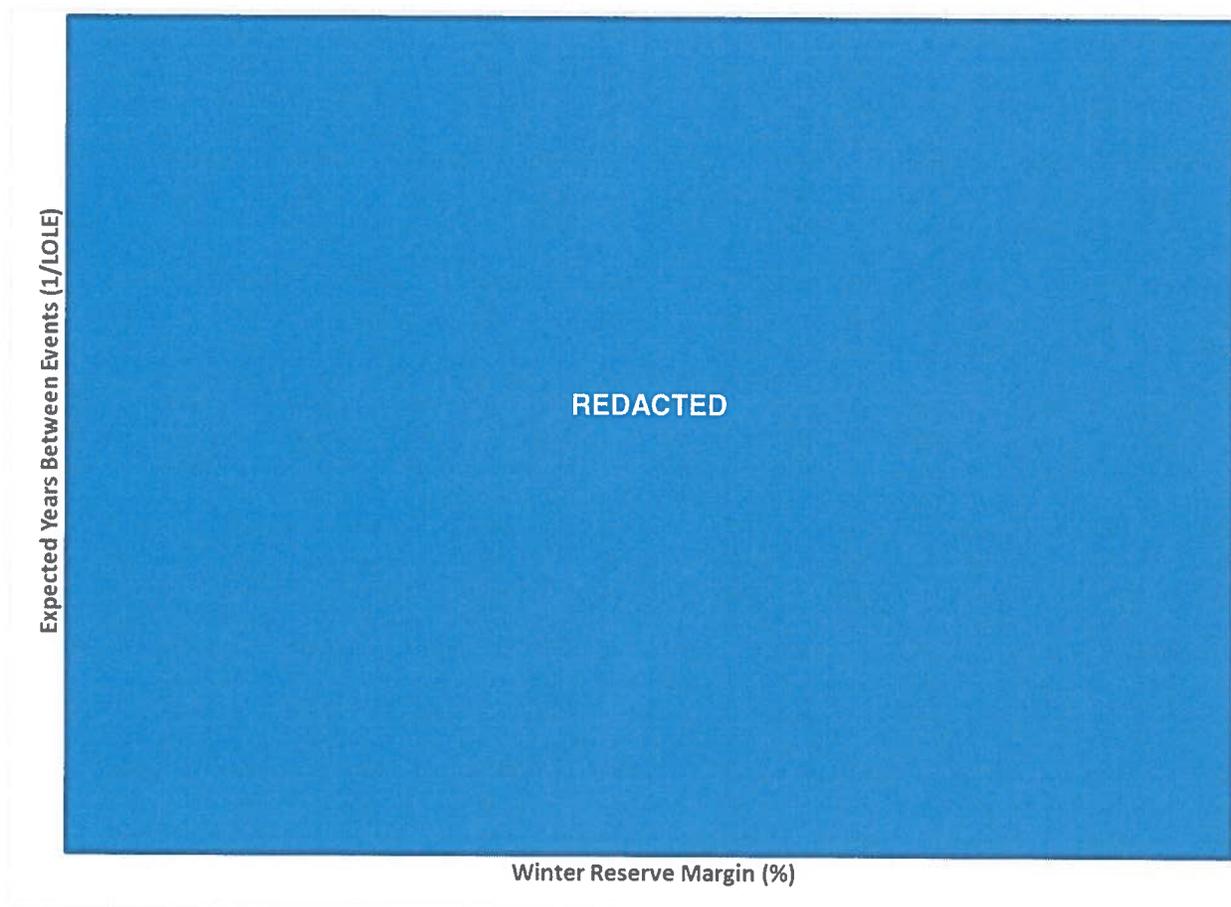
Figure III.9 LOLE for Winter Reserve Margins

At the winter EORM of 22.5%, the LOLE is **REDACTED** or an expectation of one event every REDACTED. To achieve a 1:10 LOLE threshold would require a winter reserve margin of 25.25%. In both the traditional study and the winter focus study, the 1:10 LOLE threshold is above EORM but still

Southern Company

below the VaR85 reserve margin. At the VaR85 reserve margin of 26.25%, the LOLE expectation is one event every REDACTED.

It would not be appropriate to establish a TRM that has an expected level of reliability that is lower than common industry practice. For this reason, consideration of the 1:10 LOLE threshold as a determinant in making a final TRM recommendation is necessary and appropriate.

F. Total System Cost Components

The total system cost is the sum of three components:

1) The annual carrying cost of CTs added for reserve margin (Incremental Capacity Cost);
2) Reliability Costs; and
3) Production Cost.

Following is a discussion of each component.

1) Annual Carrying Costs of CTs

The incremental annual capacity carrying cost of the added capacity at any given reserve margin is determined by multiplying the incremental CT kW capacity by its economic carrying cost. For the traditional and summer focus studies, this cost was determined using summer performance values, resulting in a carrying cost of REDACTED REDACTED. To achieve an increase of one percent reserve margin in the summer studies requires the addition of REDACTED or REDACTED in carrying cost. For the winter focus study, the cost was determined using winter performance values, resulting in a carrying cost of REDACTED. To achieve an increase of one percent reserve margin in the winter focus study requires the addition of **REDACTED** or **REDACTED** in carrying cost. As more CTs are added to achieve a higher reserve margin, these carrying costs accumulate with the megawatts added. This is represented in Figure III.10 (for the winter focus study), which shows a linear increase in costs when graphed as a function of reserve margin.

Southern Company
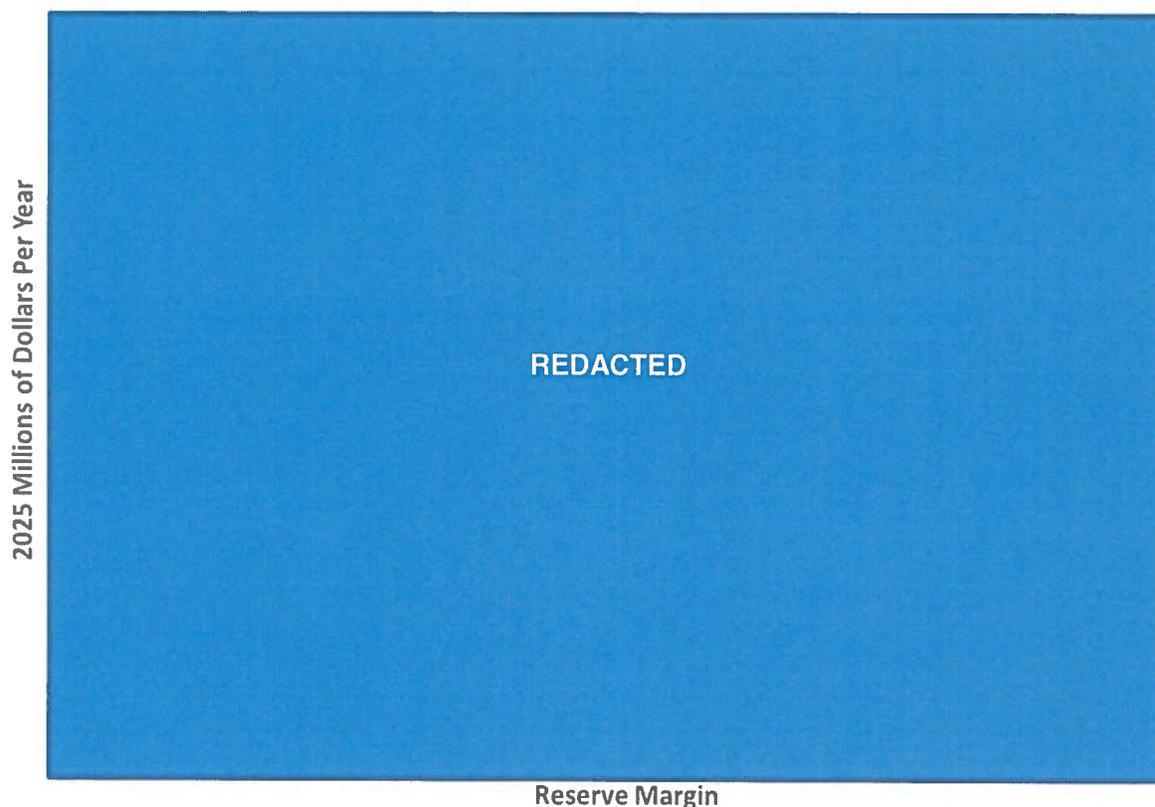
Figure III.10. Incremental Capacity Cost (Winter Focus)

2) Reliability Costs

Reliability Costs are the sum of the cost of EUE, the cost of any shortfalls in meeting required operating reserves, the cost of emergency purchases (or sales), and cost of demand response calls. The cost of EUE is determined by multiplying the amounts of EUE in MWh at each reserve level created in the analysis by the assumed cost of EUE in $/MWh (with EUE in the winter being multiplied by the winter cost of outage and EUE in all other months multiplied by the summer cost of outage). The cost of meeting shortfalls in spinning and regulating reserves are included in the cost of EUE as the model curtails load to maintain these requirements. The cost of meeting supplemental (*i.e.*, non-spin) reserve requirements is determined by the scarcity price at the time of the shortfall. The cost of demand response calls is determined by the presumed dispatch price for each demand response program as established by the Operating Companies. Figure III.11 illustrates Reliability Cost as a function of winter reserve margin.

Southern Company
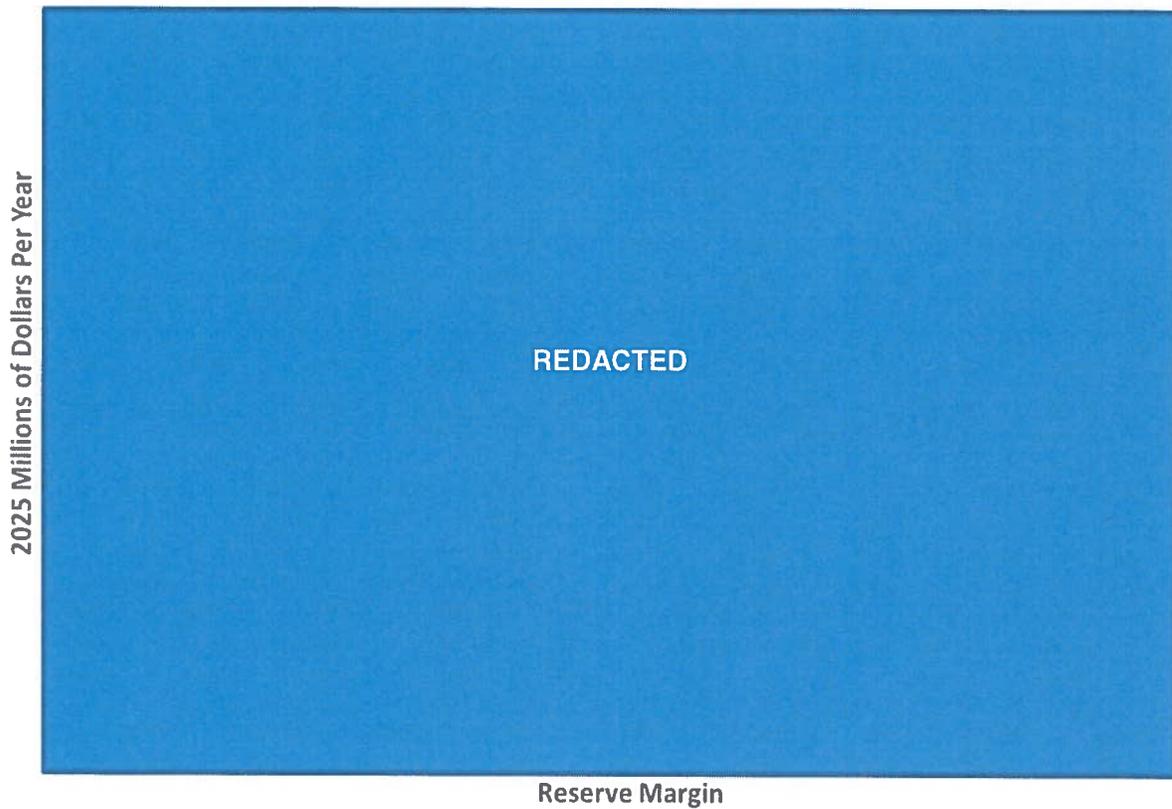
Figure III.11. Reliability Cost

3) Production Cost

Production Costs include the variable operating costs of units plus the cost of any purchases with neighboring regions less the cost of any sales with neighboring regions. Production costs at each reserve margin level can be seen in Figure III.12.

Southern Company
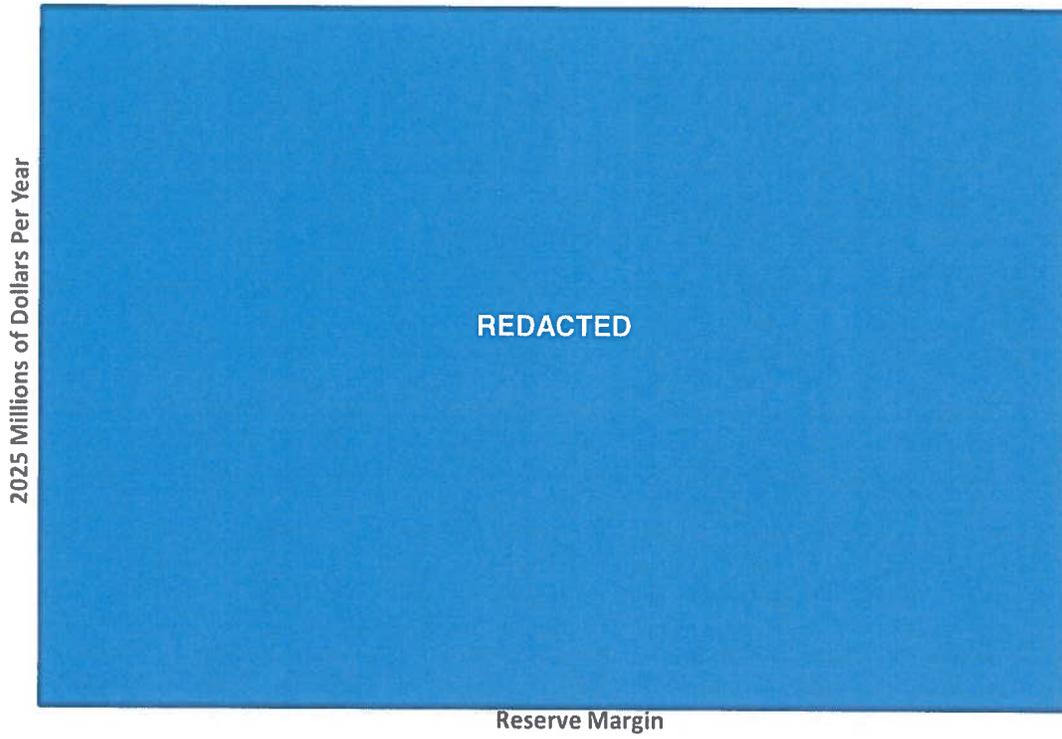
Figure III.12. Production Cost

As expected, Reliability Costs and Production Costs decrease as reserve margin increases. Conversely, their costs increase as the reserve margin is reduced.

Southern Company

IV. <u>SENSITIVITY ANALYSES</u>

The basis of the data for unit performance, weather, load forecast error, hydro availability, market prices, and other inputs is from historical information. Other data such as market availability is based on forecasted information. While the broad range of scenarios analyzed capture extreme events and market prices, there remains risk that conditions could occur in the future that extend beyond the range of what is contemplated in the base case model. Each of the following sensitivities were modeled to examine their impact on both the EORM and the 1:10 LOLE threshold.

In addition to the sensitivities related to the uncertainties above, a sensitivity was modeled to determine how the optimum reserve margin would change if the load forecast uncertainty was reduced to determine a short-term reserve margin target.

A. Capacity Price

Capacity price has an inverse impact on the EORM. The EORM calculation assumes the addition of a reliability resource (i.e., a CT) that has little or no energy value. This ensures a fair comparison of capital cost against Production Cost and Reliability Cost. At lower capacity prices, it is economically justifiable to have a higher TRM. Conversely, if capacity prices are higher, the EORM will be lower. The capacity price used in the 2018 Reserve Margin Study represents the economic carrying cost of a CT. The capacity price sensitivity examined a range of capacity costs from values as low as the Budget 2018 Retail Capacity Price Forecast ("RCPF") to values higher than the economic carrying cost of a dual fuel CT. Figure IV.1 shows how capacity costs across these ranges affect the Winter EORM. For example, at the 2025 RCPF of **REDACTED REDACTED**, the Winter EORM moved 22.5% to more than 29%. Capacity price does not impact the 1:10 LOLE threshold.

Southern Company
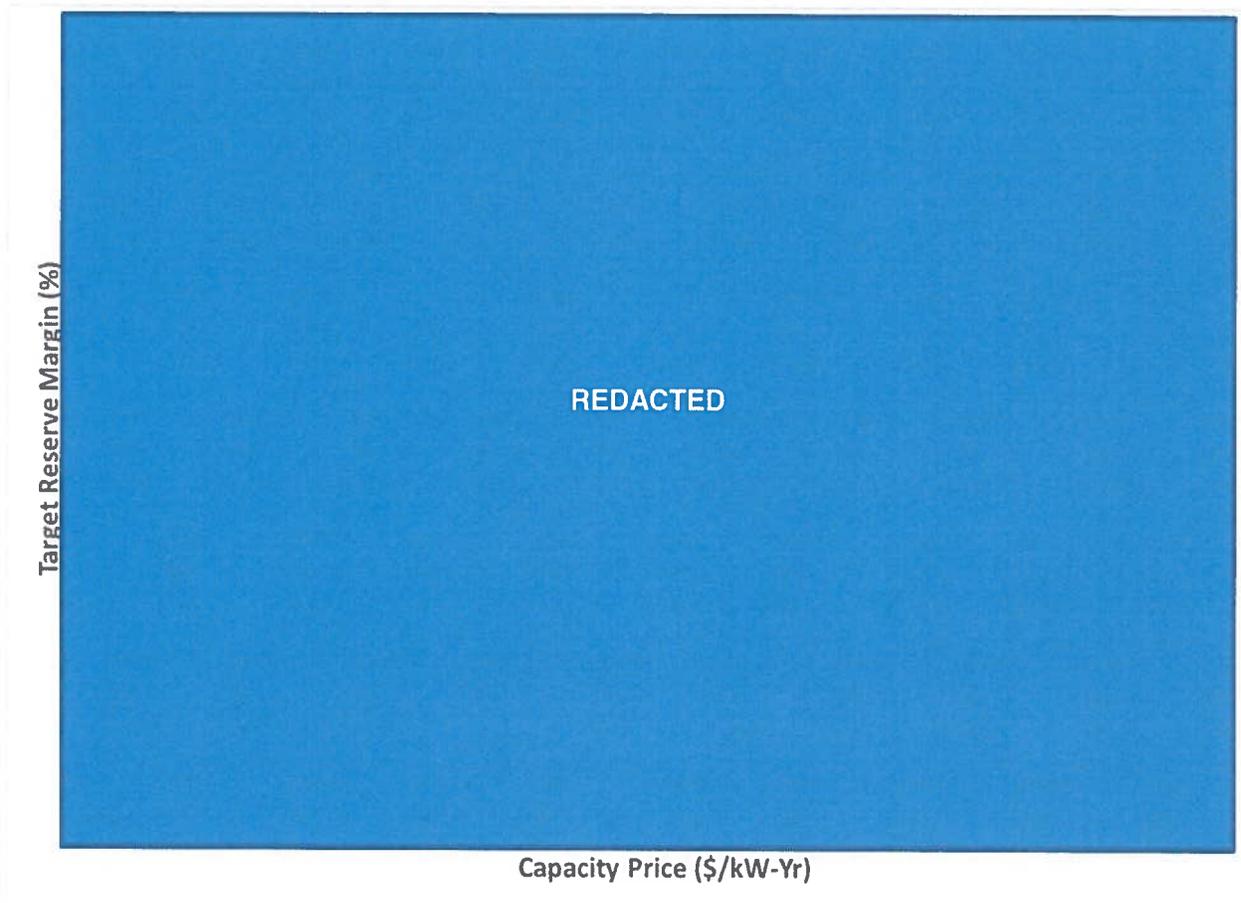
Figure IV.1. EORM as a Function of Capacity Price

B. Minimal Cost of EUE

Two cost-of-EUE sensitives were evaluated. The first was a minimum value assuming only impacts from residential class customers. This resulted in a cost of EUE of approximately **REDACTED** of outage (in 2025$). The Winter EORM for this sensitivity moved from 22.5% to 20.5%. There was no change in the 1:10 LOLE threshold.

C. Publicly Available Cost of EUE

The second cost of EUE sensitivity was one that was developed based on publicly available cost of EUE data. Using the Interruption Cost Estimate Calculator, developed by Nexant and funded by Lawrence Berkeley National Laboratory and the Department of Energy and is publicly available at http://icecalculator.com, a cost of EUE for the System was estimated to be approximately REDACTED

Southern Company

REDACTED. The Winter EORM for this sensitivity moved from 22.5% to 23.0%. There was no change in the 1:10 LOLE threshold.

D. No Cold Weather Outage Improvements

As indicated in the Section I, Assumptions, the cold weather outage assumptions used in the 2018 Reserve Margin Study incorporated substantial unit performance improvements over historical actual performance. This sensitivity assumes those performance improvements are not realized and the future cold-weather outage performance is consistent with historical performance. The Winter EORM for this sensitivity did not significantly change from the base case. However, the 1:10 LOLE threshold moved from 25.25% to 25.75%.

E. Higher Scarcity Price Curve

For the 2018 Reserve Margin Study, the scarcity price curve was updated, resulting in significantly lower scarcity price curves. Because the scarcity price curve is based on recent historical market conditions, it is possible that the current assumptions for the scarcity price curve are biased low due to the general high levels of current reserve margins throughout the neighboring regions. As the actual reserve margins in the neighboring regions all decrease towards their respective target reserve margins, it is anticipated that scarcity prices could return to levels seen previously. This sensitivity assumes that the scarcity price curve would be more consistent with that used in prior reserve margin studies (2012 and 2015). The Winter EORM for this sensitivity moved from 22.5% to 23.75%. The 1:10 LOLE threshold moved from 25.25% to 24.75%.

F. 50% Reduced Transmission

For this sensitivity, transmission capabilities with neighboring regions were reduced by 50%. This resulted in an increase in the Winter EORM from 22.5% to 23%. It also resulted in an increase in the 1:10 LOLE threshold from 25.25% to 25.5%.

G. 50% Increased Transmission

For this sensitivity, transmission capabilities with neighboring regions were increased by 50%. The results of the 50% increased transmission scenario showed no change in the Winter EORM. However, the 1:10 LOLE threshold decreased from 25.25% to 25%.

Southern Company

It should be noted that both the 50% Reduced Transmission sensitivity and 50% Increased Transmission sensitivity only resulted in marginal changes in reliability (with little or no change in economics). Together, this indicates that transmission interface capability with the interconnected regions is adequate from a reliability standpoint.

H. 50% Higher Base EFOR

For this sensitivity, base level unit outages were increased by 50%. Incremental cold-weather outages were not impacted by the sensitivity. The 50% higher unit outage scenario resulted in an increase in the Winter EORM from 22.5% to 23.25%. Similarly, the 1:10 LOLE threshold increased from 25.25% to 26.75%.

I. 50% Lower Base EFOR

For this sensitivity, base level unit outages were decreased by 50%. Incremental cold-weather outages were not impacted by the sensitivity. The 50% lower unit outage scenario resulted in a reduction in the Winter EORM from 22.5% to 21.55%. Similarly, the 1:10 LOLE threshold decreased from 25.25% to 23.75%.

Summary of Sensitivity Analyses

Figure IV.2 below shows a graphical representation of the results of all the sensitivity analyses (i.e., Sensitivities A through I). For Sensitivity A (capacity costs), two results are shown, representing capacity prices associated with the Budget 2018 RCPF (A) and ½ of the economic carrying cost of a CT (A'). The chart shows both Winter EORM and the 1:10 LOLE threshold. Together, they demonstrate that the sensitivity analyses validate the base case results of the 2018 Reserve Margin Study and indicate that its results are robust against those sensitivities.

Southern Company
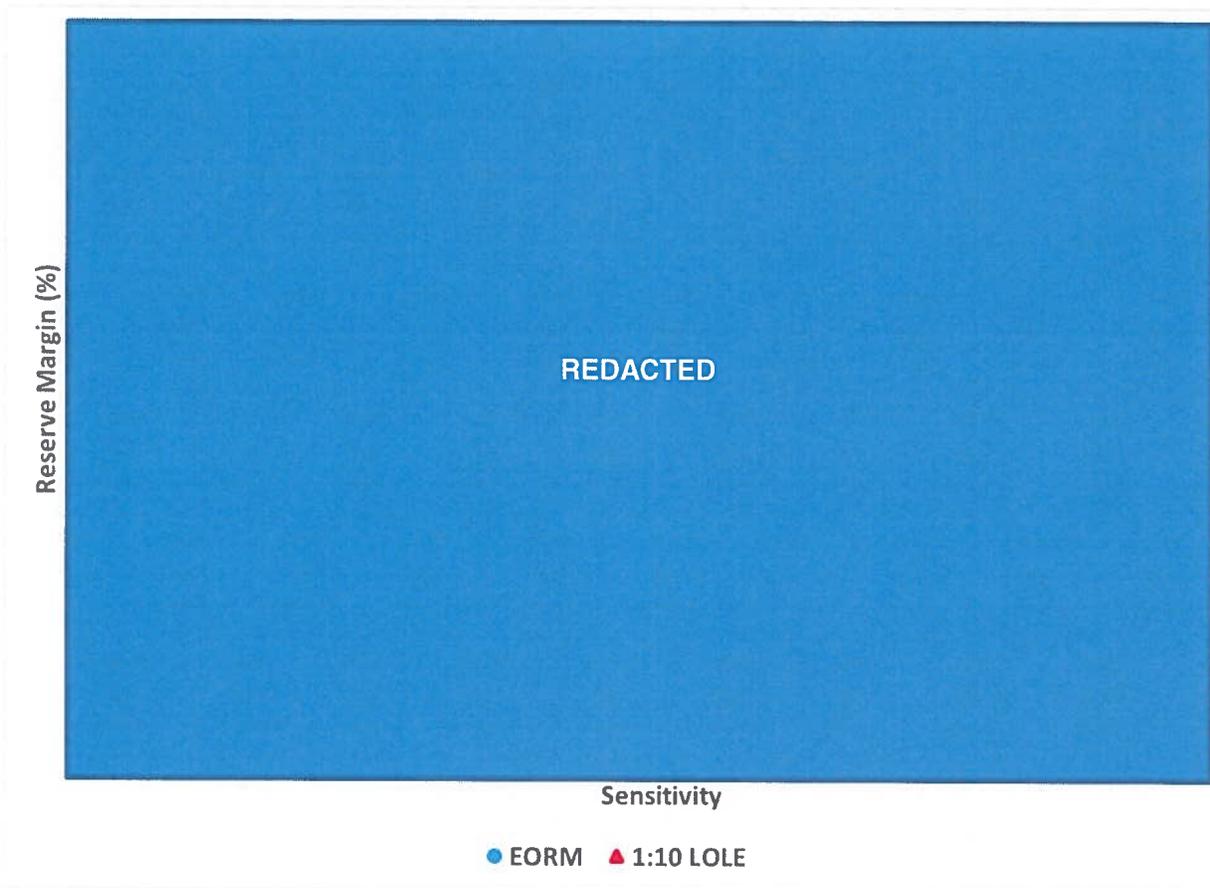
Figure IV.2. Summary of Winter Sensitivity Results

Short-Term Load Forecast Error

For this sensitivity, short-term load forecast errors were used. This sensitivity resulted in the Winter EORM decreasing from 22.5% to 22.0%, reflecting a difference in long-term and short-term reserve margins of 0.5%. The short-term load forecast errors used are in the following table.

Southern Company

Table IV.1. Short-Term Load Forecast Error

SHORT-TERM LOAD FORECAST ERROR	
LFE	**Probability**
REDACTED	0.0833
REDACTED	0.1250
REDACTED	0.25
REDACTED	0.2917
REDACTED	0.1667
REDACTED	0.0833

Southern Company

V. <u>CONCLUSION</u>

Winter reliability issues drive the 2018 Reserve Margin Study results. Therefore, a Winter TRM is required to ensure the appropriate level of resource adequacy.[13] However, it is necessary to establish both a Winter TRM and a Summer TRM for several reasons. It is possible that capacity needs can be driven by either season and should be considered when adding new capacity. In addition, there is the potential that, over time, changes in rate structures, demand-side programs, and other initiatives could alter the dynamics of the system such that the primary risk shifts between seasons. Therefore, it is recommended, that a TRM be set for both seasons, with the Winter TRM established based on the results of the winter focused study and the Summer TRM established based on the summer focused study with 1:10 LOLE threshold considerations for both as discussed below.

Winter Target Reserve Margin

The 2018 Reserve Margin Study recommends a long-term Winter TRM of 26% based on the following:

1. The TRM should be greater than the 1:10 LOLE threshold of 25.25% to ensure an adequate level of reliability on the System;
2. A reserve margin of 26% represents the risk-adjusted EORM at the 80th confidence interval (the 80th percentile of risk – i.e., VaR80);
3. Compared to the 22.5% expected case EORM, a 26% risk-adjusted EORM reduces VaR at the 80th confidence interval by **REDACTED** while only increasing expected cost by **REDACTED**;
4. Compared to the 25.25% 1:10 LOLE threshold, a 26% risk-adjusted EORM reduces VaR at the 80th confidence interval by **REDACTED** while only increasing expected cost by **REDACTED**; and
5. A 26% Winter TRM is consistent with results from the 2015 Reserve Margin Study,[14] confirming the results of that study.

---

[13] See Appendix A for further justification of the need for a Winter TRM.

[14] In the 2015 Reserve Margin Study, "An Economic Study of the System Planning Reserve Margin for the Southern Company System" (January 2016), the winter equivalent of the approved 16.25% TRM would have been 26%.

Southern Company

Summer Target Reserve Margin

The Summer EORM from the summer focus study is 14.0%, with the VaR85 reserve margin being 18%. However, the Summer TRM cannot be determined without consideration of the Winter TRM. If the System is meeting its 26% Winter TRM requirement with resources that provide year-round capacity, the summer reserve margin will generally be at or above 17.3%. This means that the Winter TRM is driving the System reliability, even though the next capacity need for one or more of the Operating Companies may still be in the summer. However, in the event seasonal resources (such as winter-only resources) are made available, it may be possible to lower the Summer TRM below 17.3% - so long as the combined annual reliability remains above the 1:10 LOLE threshold. The following graph demonstrates the minimum acceptable Summer TRM as a function of Winter TRM. For a Winter TRM of 26%, the minimum acceptable Summer TRM is REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED.
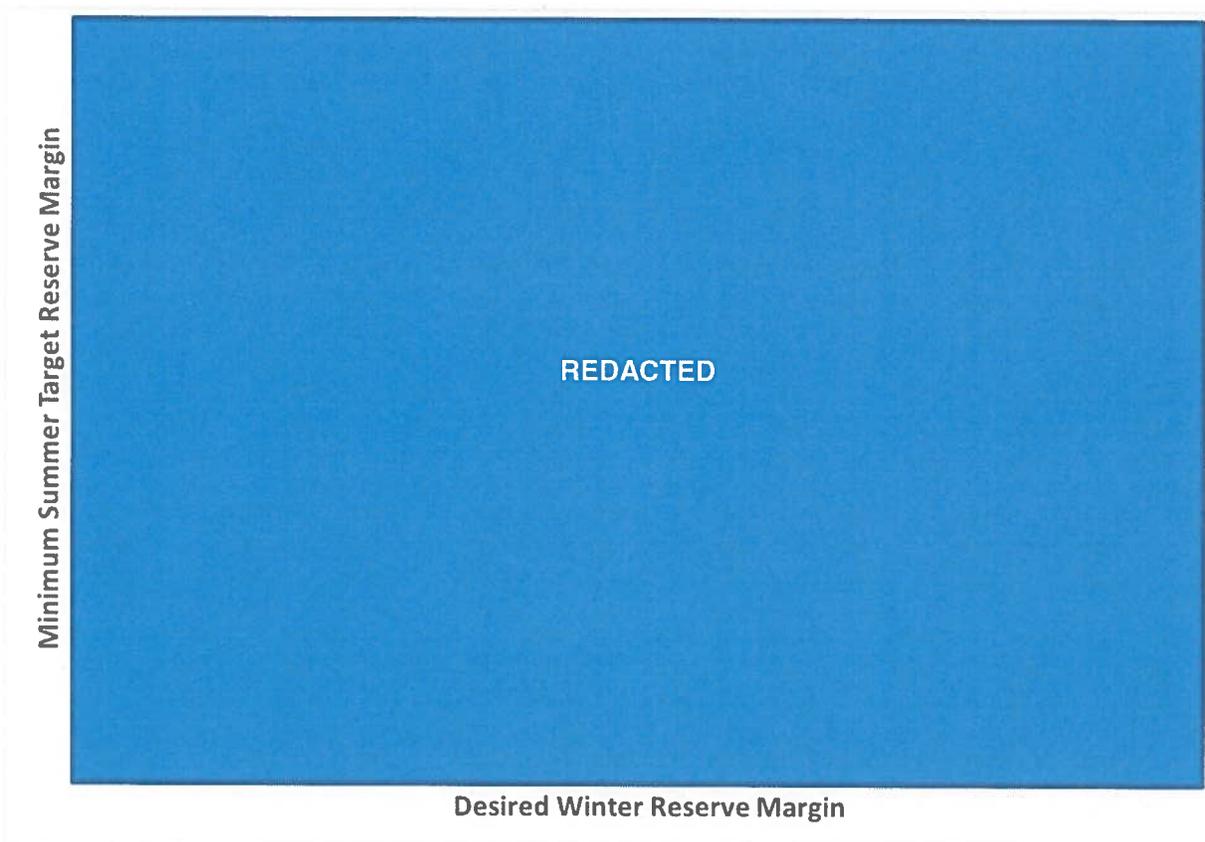
Figure V.1. Minimum Acceptable Summer Target Reserve Margins

Southern Company

The recommendation, therefore, is to establish a Winter TRM of 26%, while maintaining the currently approved 16.25% as the Summer TRM. This recommendation would apply for studies looking out four or more years. For studies looking inside a three-year window, the recommended Winter and Summer TRM are 25.5% and 15.75%, respectively, reflecting a 0.5% reduction from the long-term TRM resulting from the difference between the long-term forecast error and the short-term forecast error.

These recommendations are designed to provide guidance for resource planning decisions but should not be considered absolute requirements. The large size of capacity additions, the availability and price of market capacity (as indicated by the Capacity Cost sensitivity), or economic changes may justify decisions that result in reserve margins above these targets.

Components of the Target Reserve Margin

Figure V.2 shows the contribution of each of the components of uncertainty (weather, market risk, unit performance, load forecast error, and fuel supply) toward the overall required Winter TRM of 26%.

REDACTED
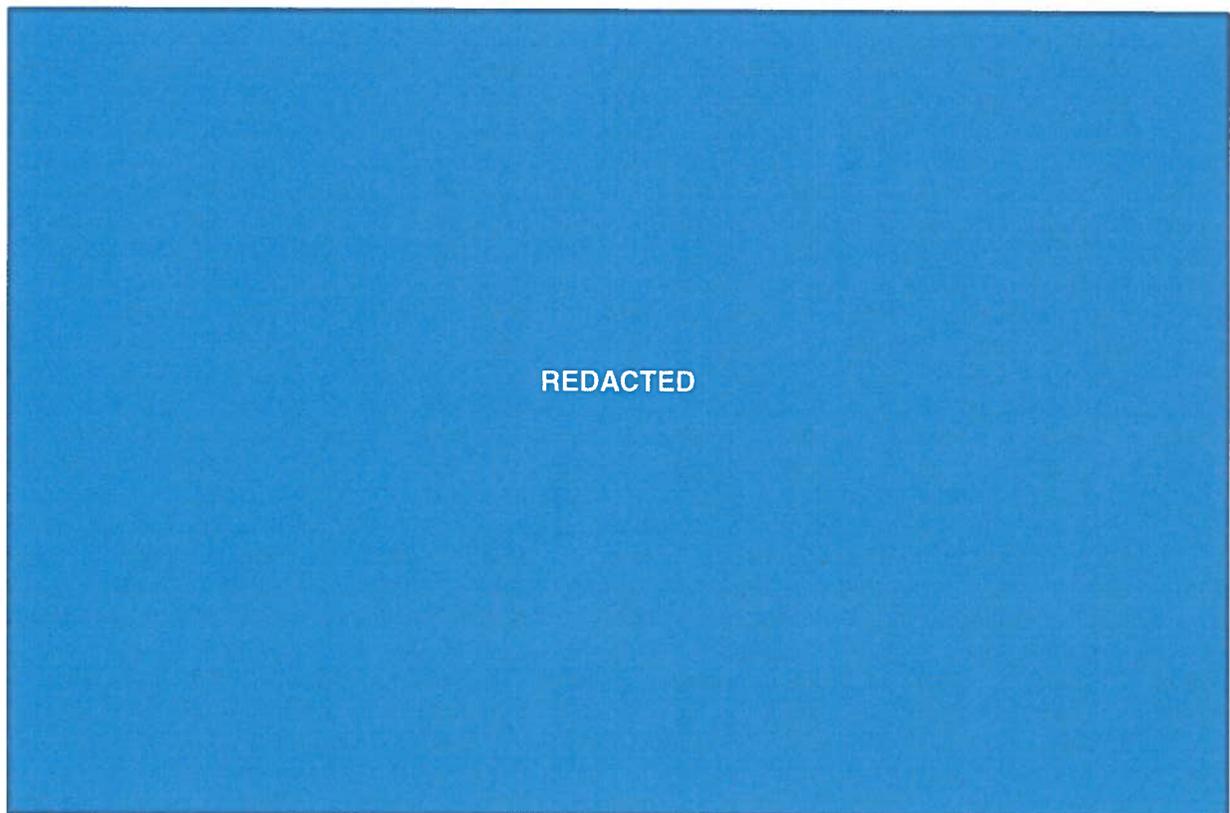
Figure V.2. Economic Components of Winter TRM

Southern Company

Likewise, Figure V.3 shows how each of the components contribute to the minimum Summer TRM of 16.25%.
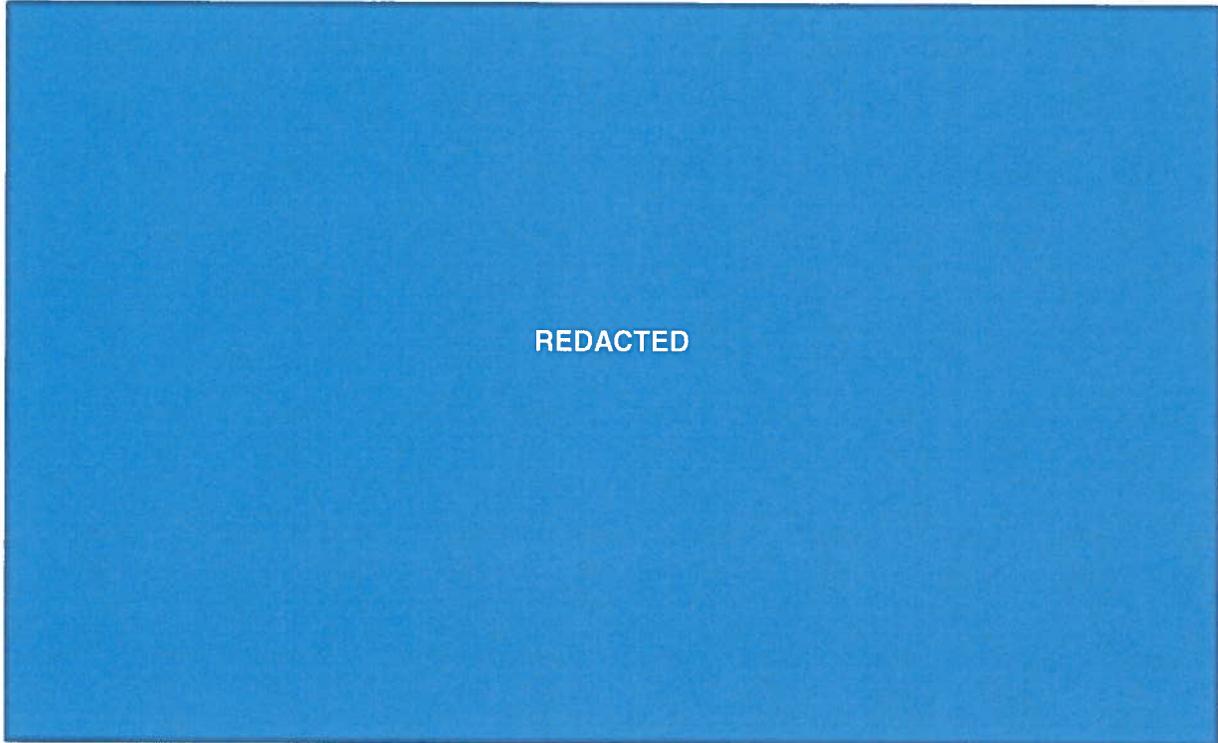
Figure V.3. Economic Components of Summer TRM

The 26% Winter Target Reserve Margin recommended for the System reflects the results of the economic study and a variety of other information available and is extremely important in planning to best meet customer needs and provide for a more reliable generation system. The 16.25% minimum Summer TRM is necessary to ensure the combined summer and winter reserve margins remain at about the 1:10 LOLE Threshold.

Southern Company

Appendix A – Examining the Need for a Winter Target Reserve Margin

A. Background

The last time that the "System" experienced an outage due to a generation shortfall was on January 17, 1977 – a winter reliability event. Since that time, the System has delivered reliable, low-cost generation even through some of the coldest weather on record during the mid-1980s. The ability to maintain reliable service during those extreme periods was primarily because the System's summer peaks were significantly higher than the System's winter peaks in that era as demonstrated in the figure below.
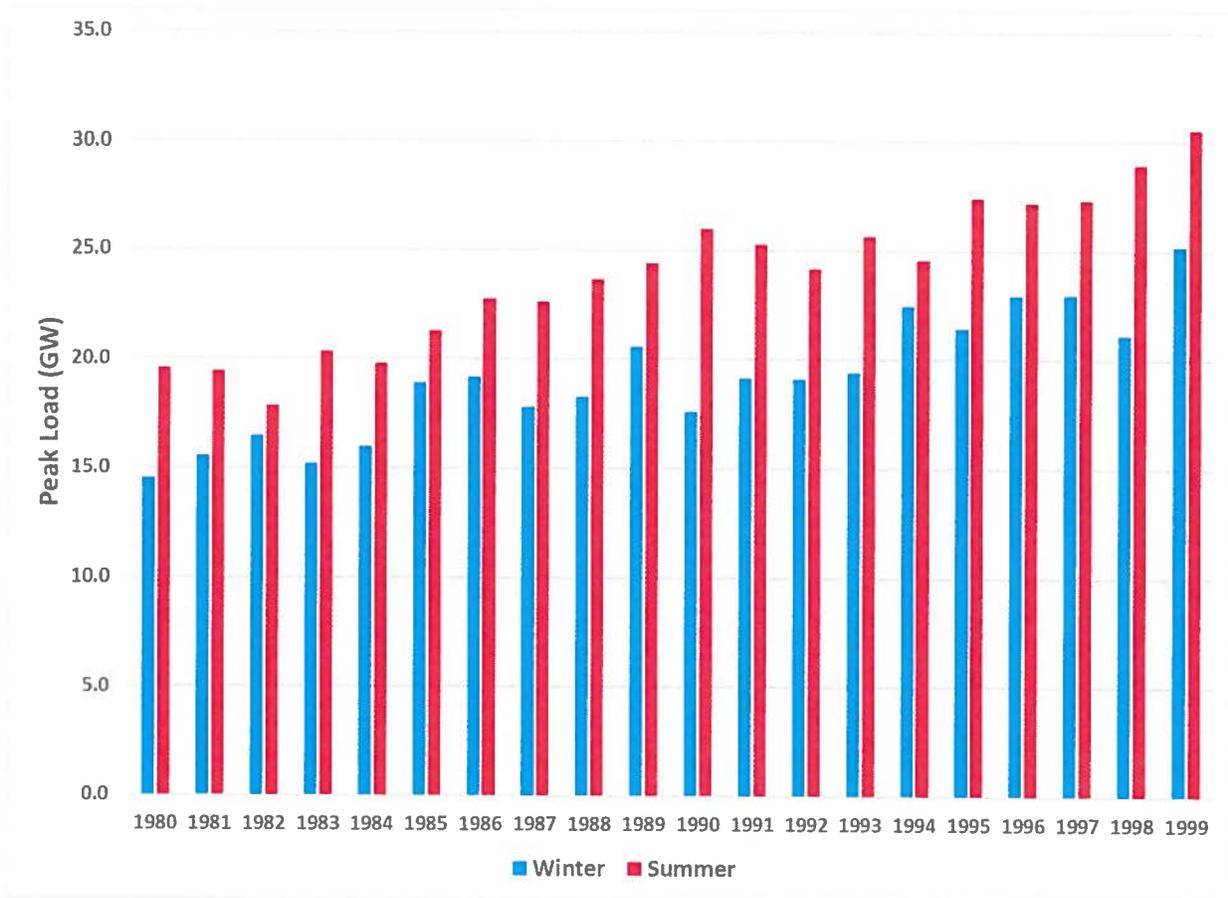
Figure A. 1. Summer and Winter Historical Peak Demands

Southern Company

In addition to being primarily summer peaking, during the 1990s and 2000s, the System only experienced one year, 1996, where system-weighted temperature fell below 10°F. During that same stretch of time, customer technology and behavior began to change. Emphasis on energy efficiency and summer demand response programs began to alter the dynamics of customer response to extreme summer and winter temperatures. That evolving response (at least as it relates to winter) was never observed due to the absence of the extreme cold-weather events. The streak without extreme cold weather ended in January 2014 with the Polar Vortex event when system-weighted temperatures reached 9°F. The chart below shows the minimum system-weighted temperatures observed on the System between 1962 and 2015.
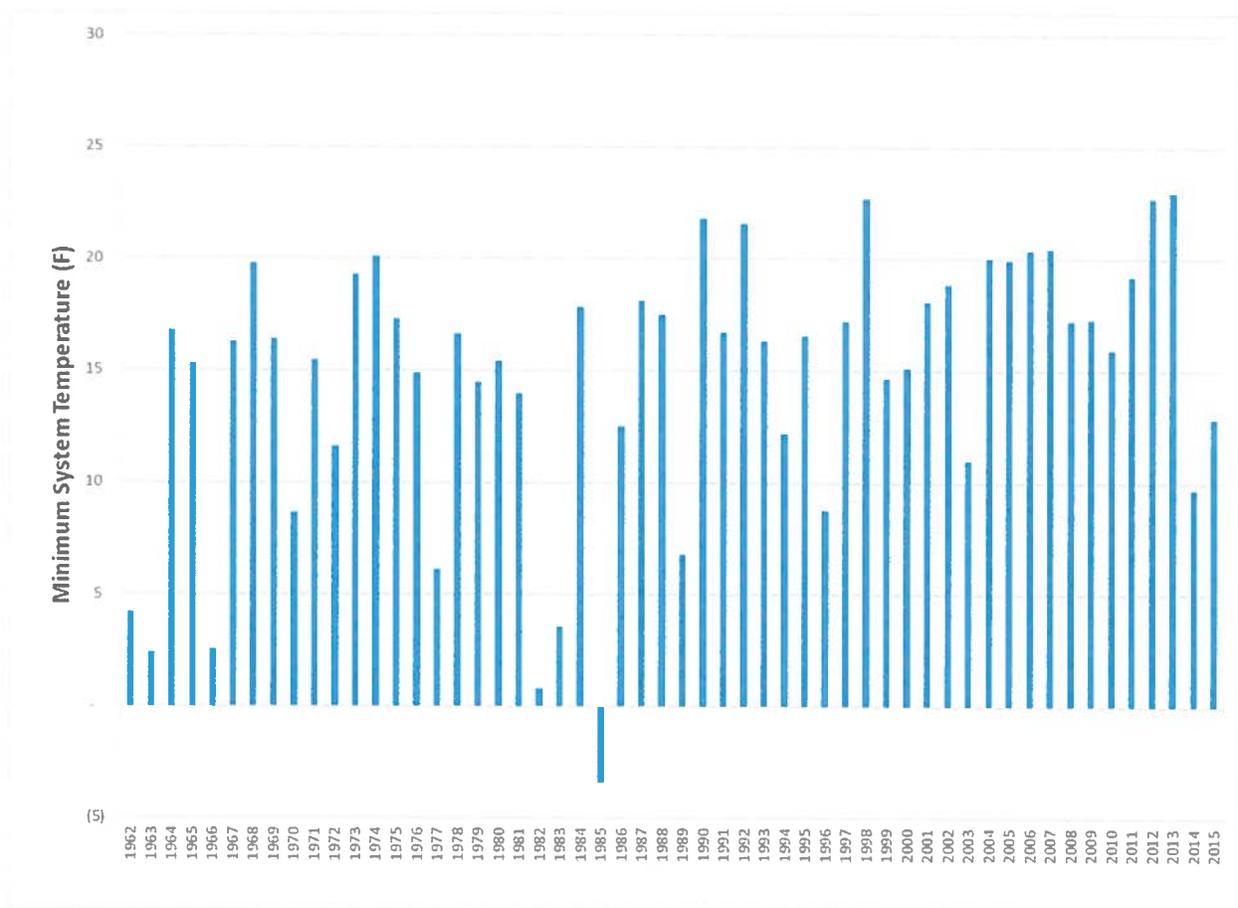
Figure A. 2. Historical Minimum System Temperatures

Southern Company

It was the 2014 Polar Vortex event in which this change in load response was first observed. At that time, the System had a reserve margin of approximately REDACTED, representing approximately REDACTED of more reserves in 2014 than what was required by the short-term TRM at that time of 13.5%. Without these additional reserves the System would have experienced a significant loss of load event during the 2014 Polar Vortex, which could have been as large as REDACTED. Similarly, the System may have also experienced such an event in the winter of 2015 but for the approximately REDACTED plus of reserves above the 13.5% short-term TRM. Between 2014 and 2018, there have been 23 winter-weather-related operations advisories,[15] including 20 times when a Conservative System Operations ("CSO") Watch[16] advisory was issued, once when the System declared Alert Level 1A,[17] once when the System declared Alert Level EEA1, and once when the System declared Alert Level EEA2.[18] By comparison, during the same period, there have been only three CSO events directly related to summer peak load conditions.

Even prior to the Polar Vortex event of 2014, operations personnel began expressing concern over reliability risks during the winter peak period. On August 16, 2011, the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) issued a report and guidance document expressing the need to be concerned with winter reliability issues. That report, *Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices*,[19] was developed after a February 2, 2011 event in ERCOT in which approximately 1.3 million electric customers did not have service during the winter peak demand of that day. The Operating Companies, however, had already been performing such assessments beginning in 2007 for the 2008 Winter Peak Period. Those assessments first began indicating the potential for a reliability concern when the assessment performed in 2009 for the 2010 winter peak noted "Possible Gas Scheduling Restrictions" as a challenge. The list of challenges expanded each year forward from that point.

---

[15] Based upon report generated by Southern Balancing Authority Area.
[16] A CSO is issued when there is an expectation of high load that warrants extreme caution during operations.
[17] A Southern Balancing Authority Area internal "alert" that occurs just prior to NERC Alert Level EEA1.
[18] EEA1 and EEA2 are system alert levels defined by the North American Electric Reliability Corporation ("NERC").
[19] Document accessible from NERC at

https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Generating_Unit_Winter_Weather_Readiness_final.pdf.

Southern Company

Currently, there are six primary determinants (discussed in more detail below) that have been identified as key drivers affecting the winter reliability risk concerns on the System, including

- the narrowing of summer and winter weather-normal peak loads,
- the distribution of peak loads relative to the norm,
- cold-weather-related unit outages,
- the penetration of solar resources,
- increased reliance on natural gas, and
- market purchase availability.

Prior to the 2015 Reserve Margin Study, [20] most of these drivers were unobserved and unmodeled in the reliability planning model. The 2015 Reserve Margin Study made a first attempt at modeling these drivers, resulting in an increase in Target Reserve Margin from 15% to 16.25%. Since the 2015 Reserve Margin Study, planners have continued efforts to refine both the modeling assumptions and the modeling techniques surrounding these drivers. In the process, it has become evident that the most effective way to plan for and manage these reliability risks is to establish a Winter Target Reserve Margin.

B. Key Drivers

The six primary drivers affecting the winter reliability risk issue are discussed in the following sections.

B.1 Narrowing of Summer and Winter Weather-Normal Peak Loads

On a weather-normal basis, the System remains a summer peaking utility. However, over the course of the last 10-15 years, the gap between the weather-normal summer peak load and the weather-normal winter peak load has narrowed. Figure A. 3 below shows the one-year ahead forecasted peak loads since 2006 as well as the Budget 2018 forward-looking longer-term forecast. The graph shows how the gap between the summer and winter weather-normal forecasted peak loads has narrowed since 2006 from greater than REDACTED to less than REDACTED.

---

[20] An Economic Study of the System Planning Reserve Margin for the Southern Company System, January 2016.

Southern Company

Because the gap between these peaks has narrowed – and are likely to remain closer in the future – the System has less flexibility to handle any significant variations in seasonal reliability such as those described in the remaining sections below. Therefore, it becomes necessary to examine System performance in the winter independently from the summer through a Winter Target Reserve Margin.

REDACTED

——Winter ——Summer
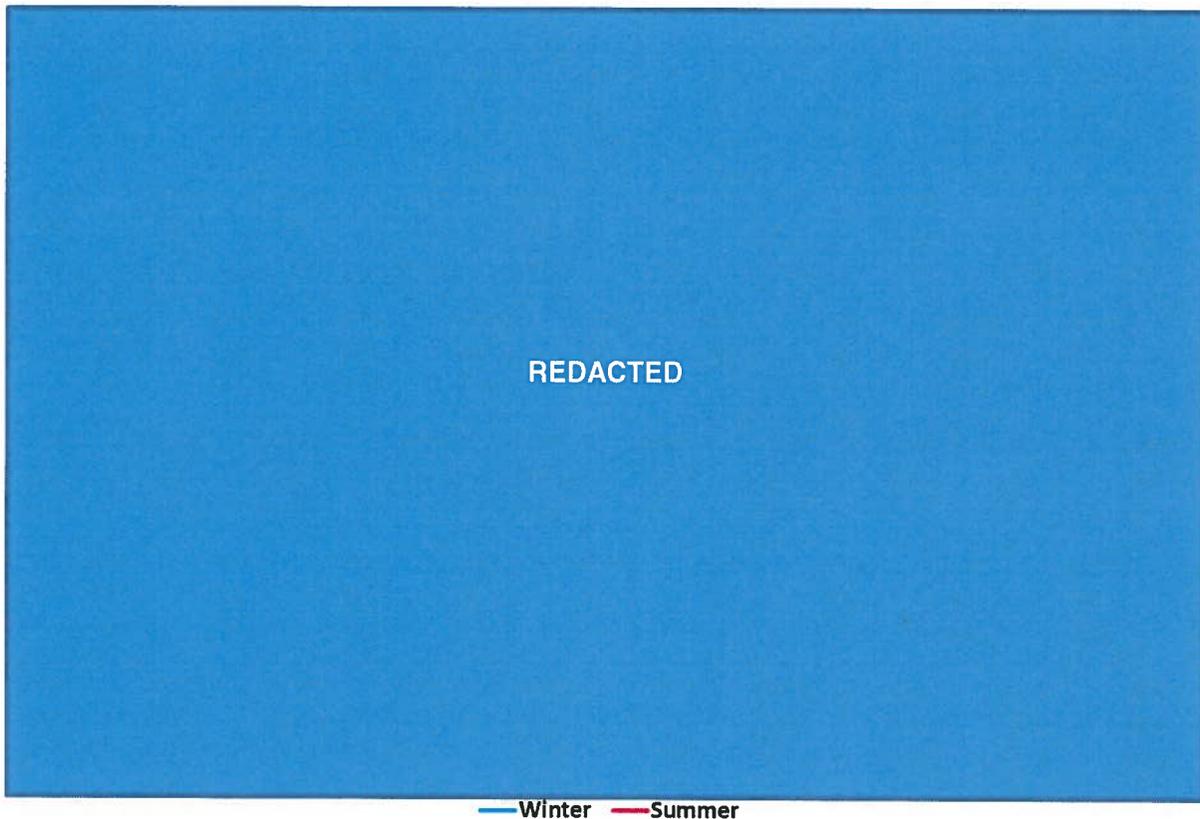
Figure A. 3. Historical Forecasted Weather Normal Peak Loads

B.2 Distribution of Peak Loads Relative to the Norm

As discussed in the Background section above, customer load response has changed such that response to abnormal weather conditions in the winter is more volatile than the summer. One of the primary purposes of the TRM is to have the resources necessary to handle these abnormal weather conditions. In both the summer and the winter, there is a probability distribution around the forecasted weather-normal peak load. This distribution is determined by the expectation of non-weather-normal

Southern Company

conditions, represented within SERVM[21] by the 108 modeled load shapes for the 54 historical weather years. Figure A. 4 below shows the distribution of the modeled summer and winter non-weather-normal peak loads about their respected weather-normal peak load forecast. This chart shows that in the summer the peak load can be either 6.6% higher than the average or 6.8% lower than the average. In the winter, however, the peak load can as much as 22% higher than the average or 14.4% lower than the average. The chart also demonstrates that there is a significant possibility that the winter peak load in any given year can even be higher than the summer peak load.
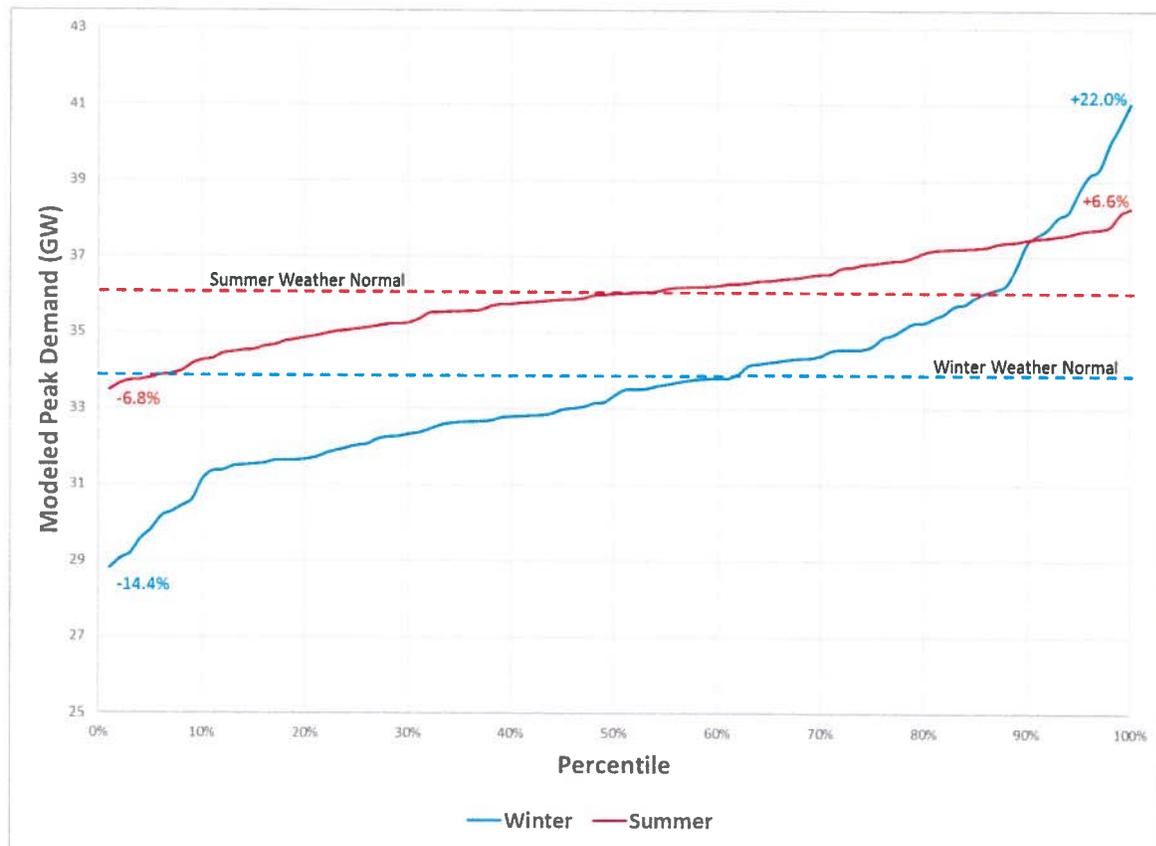
Figure A. 4. Distribution of Modeled Summer and Winter Peak Loads

---

[21] SERVM is a probabilistic reliability risk evaluation tool used in the Reserve Margin Study and other reliability analyses.

Southern Company

Of the 108 peak loads *modeled* in SERVM, there are 23 winter peaks greater than their respective summer peaks, representing roughly a 20% probability that the winter peak will be higher than the summer peak in any given year. This is consistent with what has been historically experienced. As shown in Figure A. 5 below, there have been two out of the last 10 years (2014 and 2015) in which the *actual* winter peak was higher than the actual summer peak.
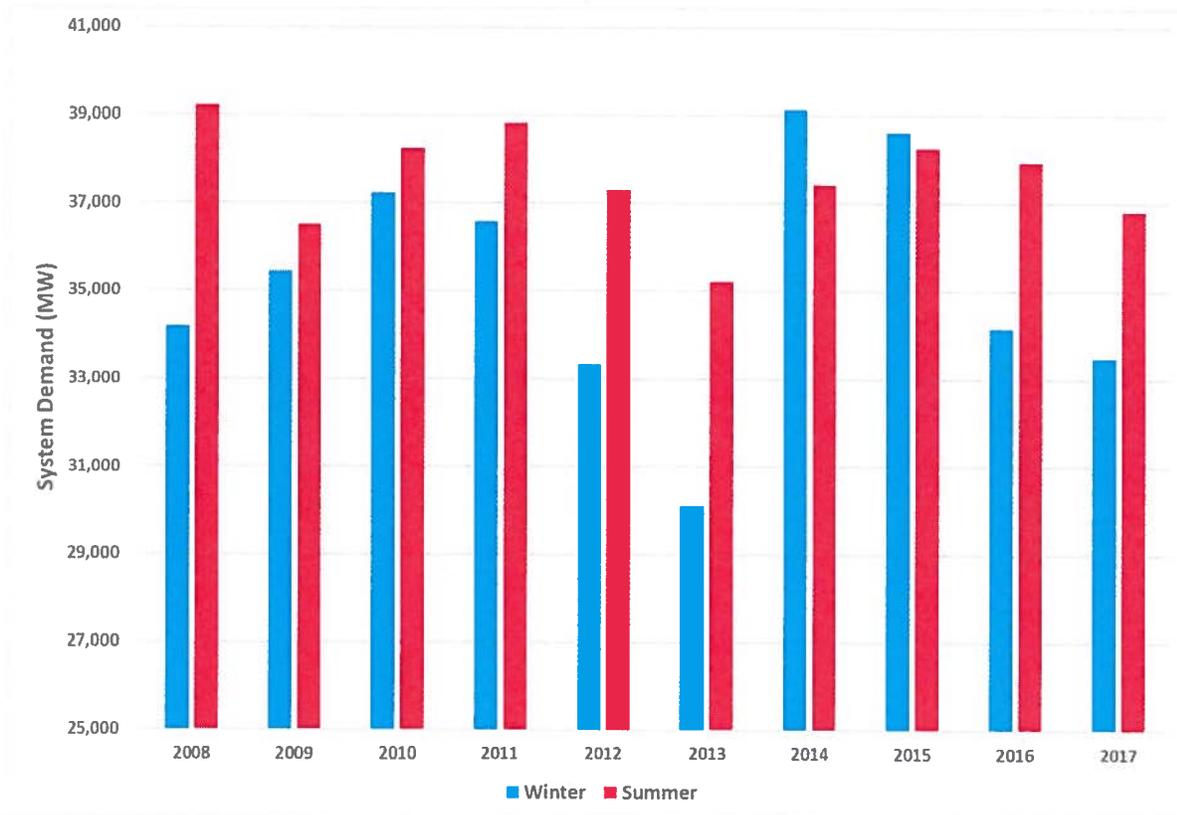
Figure A. 5. Historical Summer and Winter Peak Loads

Note: Figure shows total aggregate load dispatched within the Southern Company Pool.

B.3 Cold-Weather-Related Unit Outages

Extreme cold-weather conditions often result in increased unit outage rates. History has demonstrated that as temperatures continue to decrease the outage rate tends to increase exponentially. While the causes (*i.e.*, the components impacted by the cold weather) may be different for each, steam generators, CCs, and CTs all have vulnerabilities to extreme cold temperatures. Table A. 1 below shows several historical dates when extreme temperatures have occurred on the system. Many of

Southern Company

these caused significant outages on the system. The table demonstrates that the colder the temperature, the more likely weather-related outages will occur.

Table A. 1. Historical EFOR During Cold-Weather Events

Date of Event	System Weighted Temperature (F)	EFOR (% of System Capacity)
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED
REDACTED	REDACTED	REDACTED

After the 2014 Polar Vortex event, the Operating Companies began implementing measures to improve the performance of its resources under extreme conditions. Those measures included the development of Standards of Excellence procedures for preparing generating facilities for cold weather and the addition of freeze protection on certain vulnerable equipment. System plant performance experts are confident that these efforts to improve cold-weather performance will ultimately result in a

Southern Company

reduction in cold-weather outages relative to historical trends. However, even with these improvements, there will always remain an exponentially increasing probability of performance risk as system-weighted temperatures reach the more extreme cold levels. Figure A. 6 below shows the trend of the total System outages from Table A. 1. It also shows that same trend adjusted by an assumed average base EFOR of REDACTED, representing the incremental outage rate associated with cold weather. Finally, it shows those same incremental outage rates adjusted to reflect the expectation of improved performance over time.
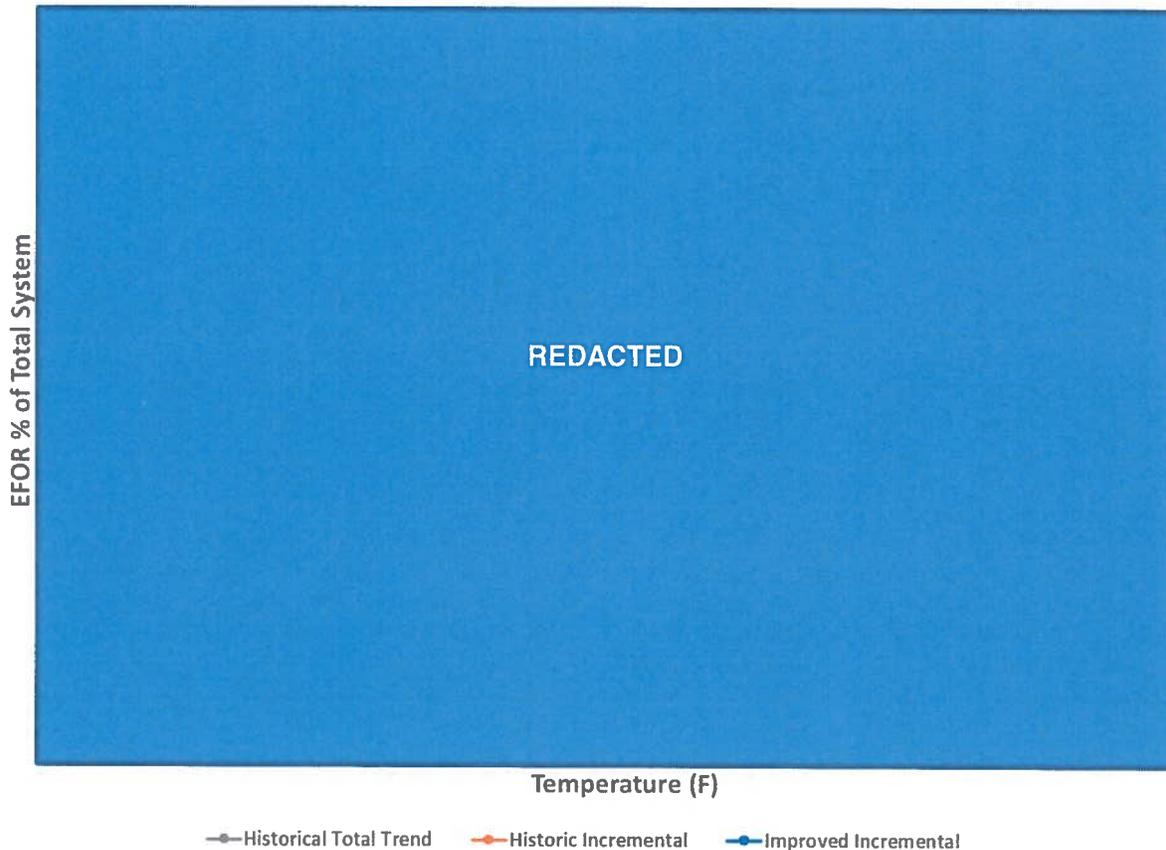
Figure A. 6. Cold Weather Unit Outage Performance

B.4 Penetration of Solar Resources

While reasonably correlated to summer peak load periods, solar generation is not well correlated to winter peak load periods, which occur around dawn or dusk. Thus, solar resources contribute significantly more toward summer reliability than they do toward winter reliability. Therefore, unless

Southern Company

planners are looking at the System from both a summer and winter TRM perspective, the addition of solar resources can give the false impression of increased overall reliability. If only the Summer TRM is considered, a significant penetration of solar resources may contribute toward meeting summer reliability needs but would not contribute significantly toward meeting winter reliability needs, leading to possible winter reliability concerns. Figure A. 7 below shows the expected penetration of solar resources on the System through 2021 along with their corresponding Incremental Capacity Equivalent ("ICE") summer and winter capacity values.
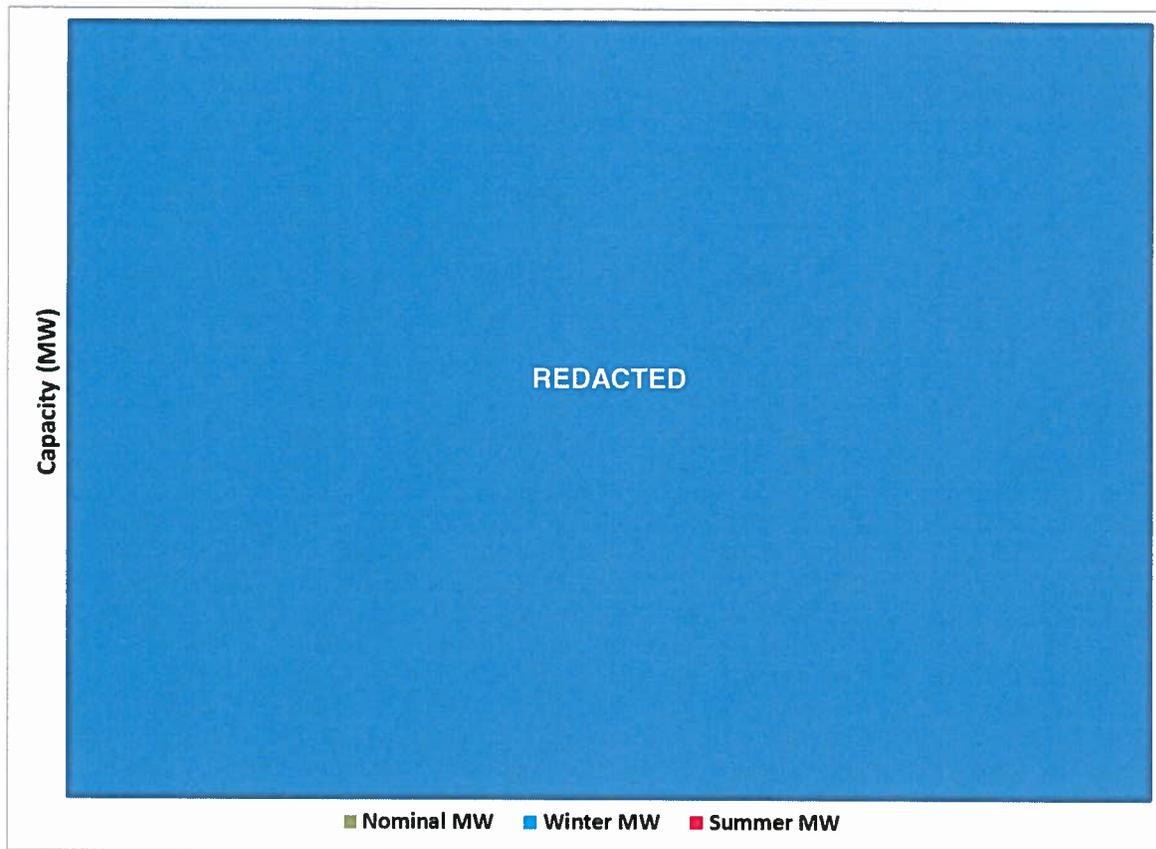
Figure A. 7. Solar Resource Penetration

This relative seasonal performance of solar resources can be confirmed by observation of actual historical solar output across the top 20 load hours of the summer and winter peak seasons for the solar resources currently installed on the System. Figure A. 8 below shows the relative summer and winter output (as a percentage of nominal installed solar capacity) on the System since 2015 averaged over the highest 20 load hours in the summer and winter periods. Note that the comparison of the

Southern Company

average output across the top load hours cannot be used to validate or compare with the ICE values because the two metrics have different meanings, and the historical observations are for only a few sample years. However, both metrics do indicate solar has significantly different contributions to reliability in the summer versus the winter, with significantly less in the winter compared to the summer.
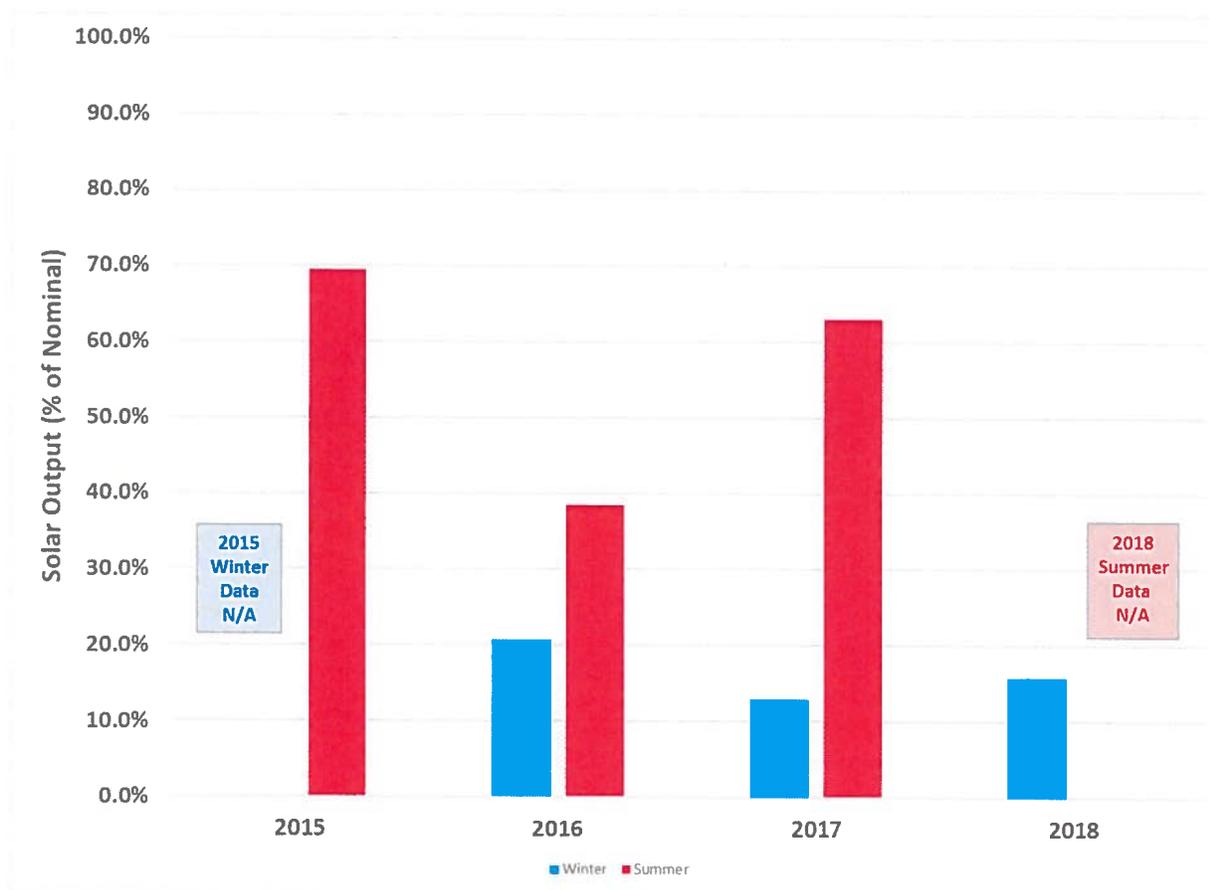
Figure A. 8. Solar Output During Highest 20 Load Hours

B.5 Increased Reliance on Natural Gas

Over the last decade, the System has increased its reliance on natural gas as a fuel source to meet its energy and demand needs. Figure A. 9 below shows the historical and future projected breakdown of energy by fuel type for the System, demonstrating the increased expectation for reliance on natural gas. The "coal or gas" slice in the 2027 Projected pie chart indicates uncertainty in coal vs. gas usage based on uncertainties in the forecasted price of natural gas.

Southern Company
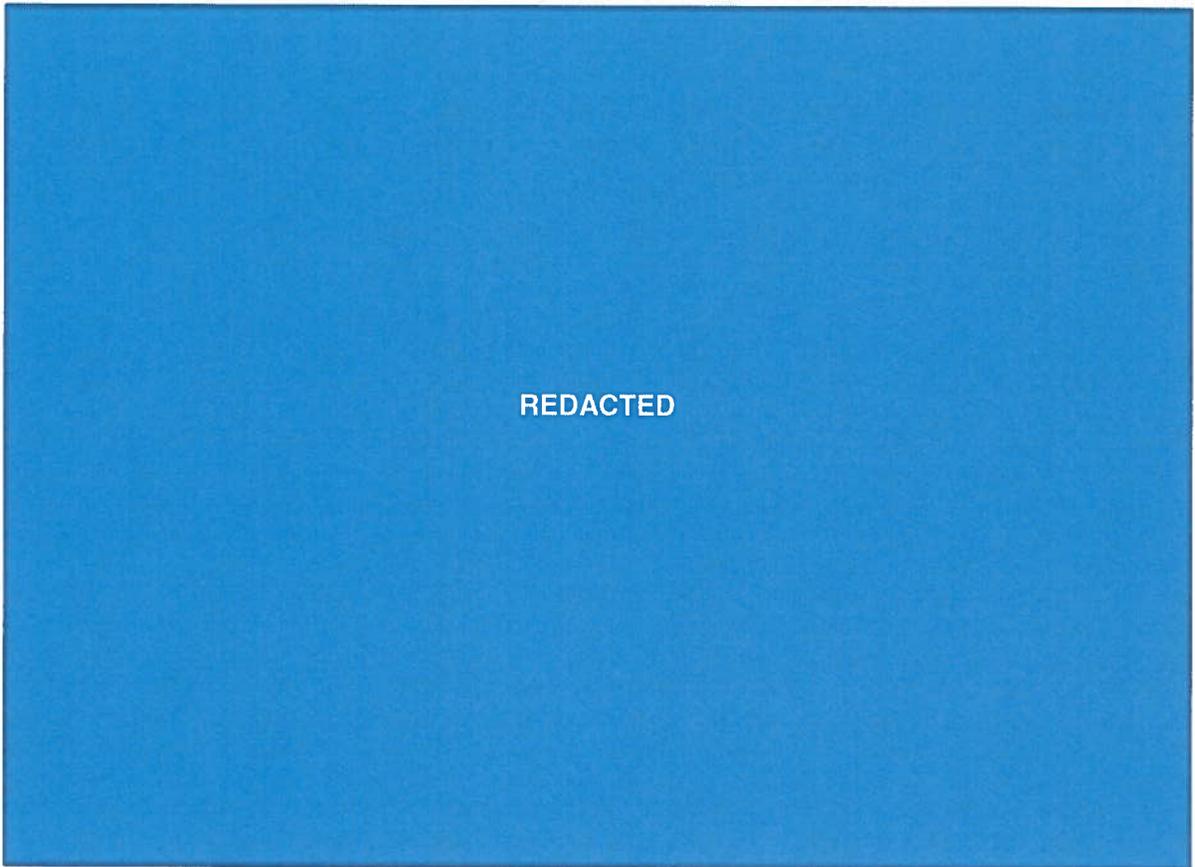
Figure A. 9. Historical and Projected Energy Use by Fuel Type

This increased reliance on natural gas increases exposure to gas delivery constraints, especially during winter peak conditions, because gas pipelines limit usage to firm transportation contracts. Figure A. 10 below demonstrates that over the last 6 years (2012 thru 2017), most operational flow orders[22] issued by the two primary pipelines that serve the System have occurred during the winter months.

---

[22] Operational flow orders are issued by pipeline operators when demand for natural gas causes constraints on the pipeline such that only those holding firm gas transportation contracts can utilize the pipeline.

Southern Company
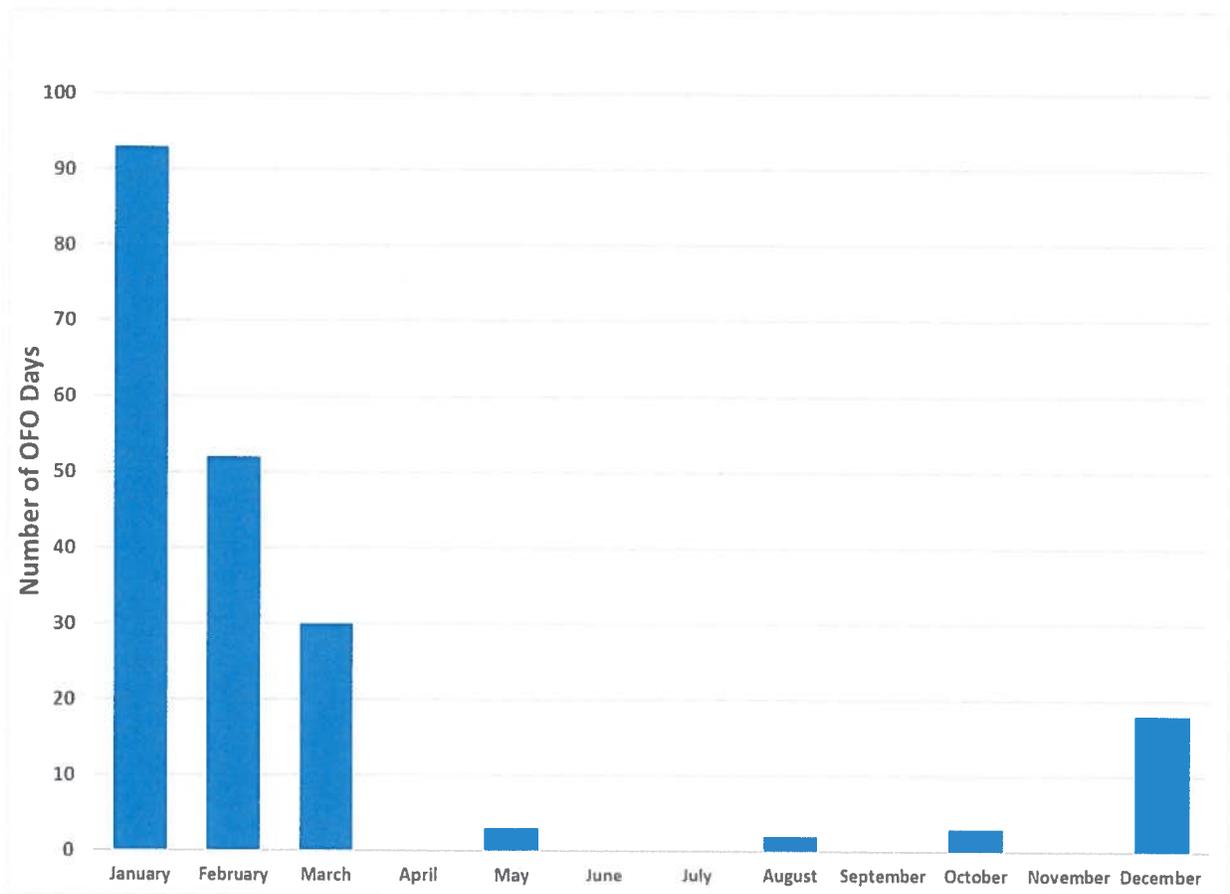
Figure A. 10. Monthly Distribution of Operational Flow Orders

To model the constraints associated with these operational flow orders, SERVM allows the user to phase out the availability of interruptible gas transportation based on the minimum and maximum daily temperature. When no interruptible transportation is available, the model only allows the unit to operate to the extent it has firm gas transportation or an alternative fuel supply such as on-site fuel storage. Figure A. 11 below shows the phase-in and phase-out of interruptible gas transportation as modeled in SERVM.

Southern Company
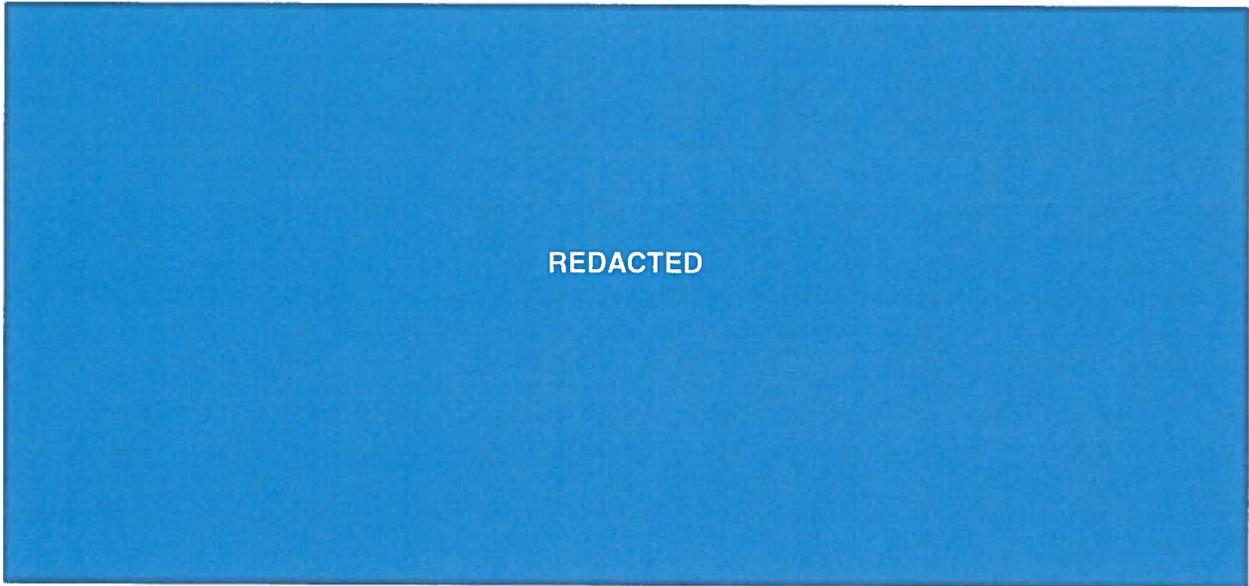
Figure A. 11. Interruptible Gas Transportation Model

To mitigate the risk against these operational flow orders, the Operating Companies have a Fuel Policy that requires either on-site backup fuel (such as oil) or the acquisition of firm gas transportation from the pipeline. For CTs, the policy requires the equivalent of REDACTED REDACTED of firm transportation. For CCs, the policy requires the equivalent of REDACTED REDACTED of firm transportation for base mode operation and REDACTED REDACTED of firm transportation for operation in full pressure modes. Unfortunately, while this policy is sufficient for typical (*i.e.*, normal) weather conditions, it can be insufficient for the most extreme weather conditions. As temperatures fall during the more extreme winter conditions, CTs may need to operate greater than REDACTED REDACTED and CCs may need to operate in full pressure mode more than REDACTED REDACTED. However, if the pipeline has issued an operational flow order, these resources will not be able to serve load once their firm gas transportation allocation has been fully utilized, resulting in unit outages during critical times causing either the need to operate more expensive oil facilities or, in the worst case, loss of load events. Additionally, the pipeline operators may limit the ability of the CTs to take the nominated natural gas across the REDACTED REDACTED and force them to take the natural gas in equal increments across 24 hours, limiting the ability to use these resources to meet peak load. The Operating Companies continue to evaluate the risk of such events against the expense of additional firm gas transportation.

Southern Company

B.6 Market Purchase Availability

Traditionally, the reserve margin studies have modeled the regions surrounding the System to incorporate the availability of economic and reliability purchases from those regions. To avoid bias in the analysis results and not include purchases that might not be available in the real world, these regions are generally modeled at or near a reasonable level of reliability – specifically, they are modeled at or near a Loss of Load Expectation ("LOLE") of 0.1 days per year. This modeling effort already results in fewer purchases during the winter than in the summer. This is due primarily to the fact that when the System experiences very high demands resulting from extreme cold temperatures, the surrounding regions also experience those extreme temperatures and demands. Figure A. 12 below shows several recent cold-weather events and the amount of purchases that were available to the System at the time of the event.
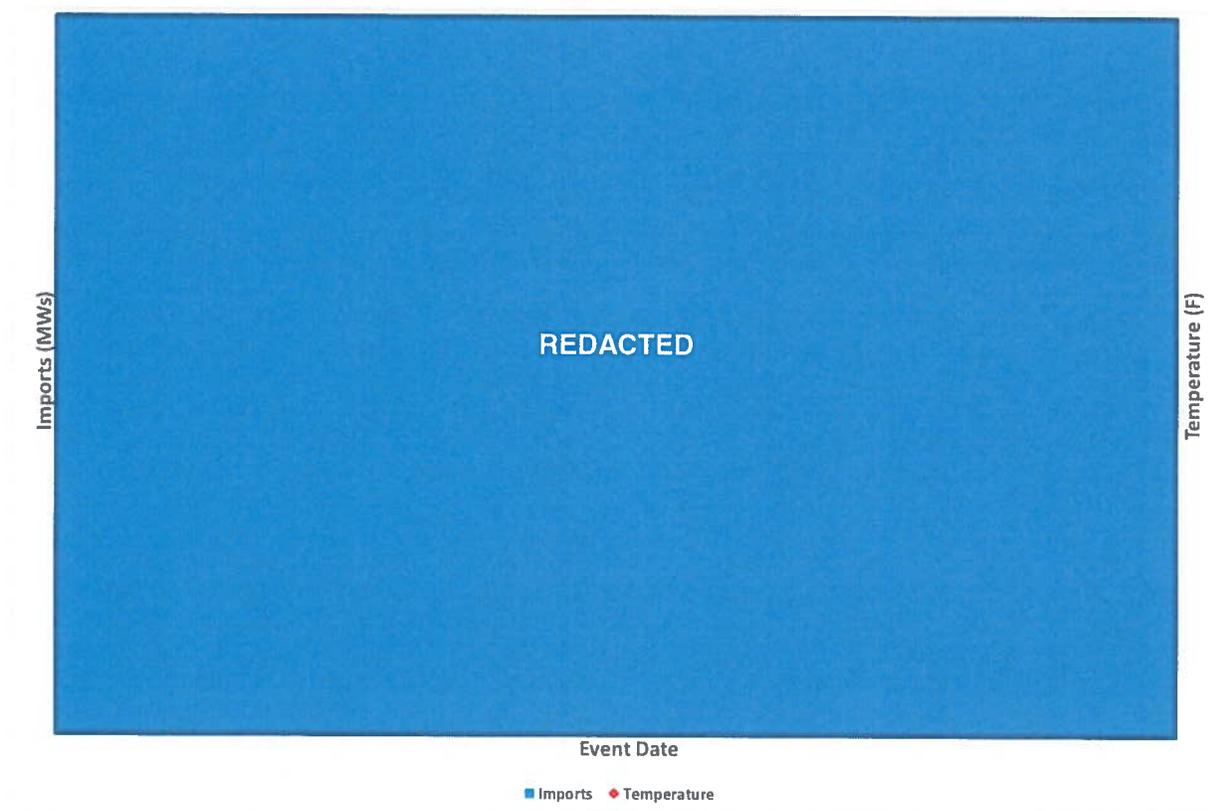
Figure A. 12. Historical Purchases During Cold-Weather Events

Southern Company

This kind of purchase availability restriction can occur during extreme summer temperatures as well, but not to the same degree as in the winter. This creates greater relative market availability risk in the winter than in the summer, further supporting the need to monitor and review winter reliability independently from summer. While absolute limits on purchases are not easily modeled within SERVM, operations personnel did provide purchase availability "targets" (rather than absolute limits) for use in the 2018 Reserve Margin Study. Those targets were implemented by a combination of sales price limitations and hurdle rates between regions.

C. Aggregate Impacts of Drivers on Winter Reliability

Over the past several years, significant efforts have been made to model these winter reliability drivers. The result has been an improvement in the reliability model that more closely matches what has been seen historically in the operational world. The following demonstrates how the modeling of these key drivers has impacted winter reliability.

### C.1 Total Available Capacity by Season

In updating unit and system assumptions, one of the impacts that has resulted is a reduction in relative capacity during the winter months as compared to the previous study. In the 2015 Reserve Margin Study, there was considerably more total available capacity at lower winter temperatures than at summer temperatures. It is still true that many resources, such as CTs and CCs, have greater capacity output during cold temperatures than they do during hot temperatures – and were modeled as such in the 2018 Reserve Margin Study. However, not all resources can be depended upon for that additional capacity. Several of the CT and CC resources available to the System are Power Purchase Agreements ("PPA") that have contractual limitations on the amount of capacity that can be depended upon on a firm basis. While the resource may be able to produce more during the winter, the System does not have firm access to that additional capacity and the counterparty may not be obligated to provide the additional capacity available in the winter. Furthermore, what additional capacity that is available from other CT and CC resources is offset by the lower capacity contributions of solar and demand-side resources in the winter relative to summer. Figure A. 13 below shows that there is very little difference in the available capacity at a System-weighted temperature of 95°F than there is at either 40°F, 20°F, or even at 10°F.

Southern Company
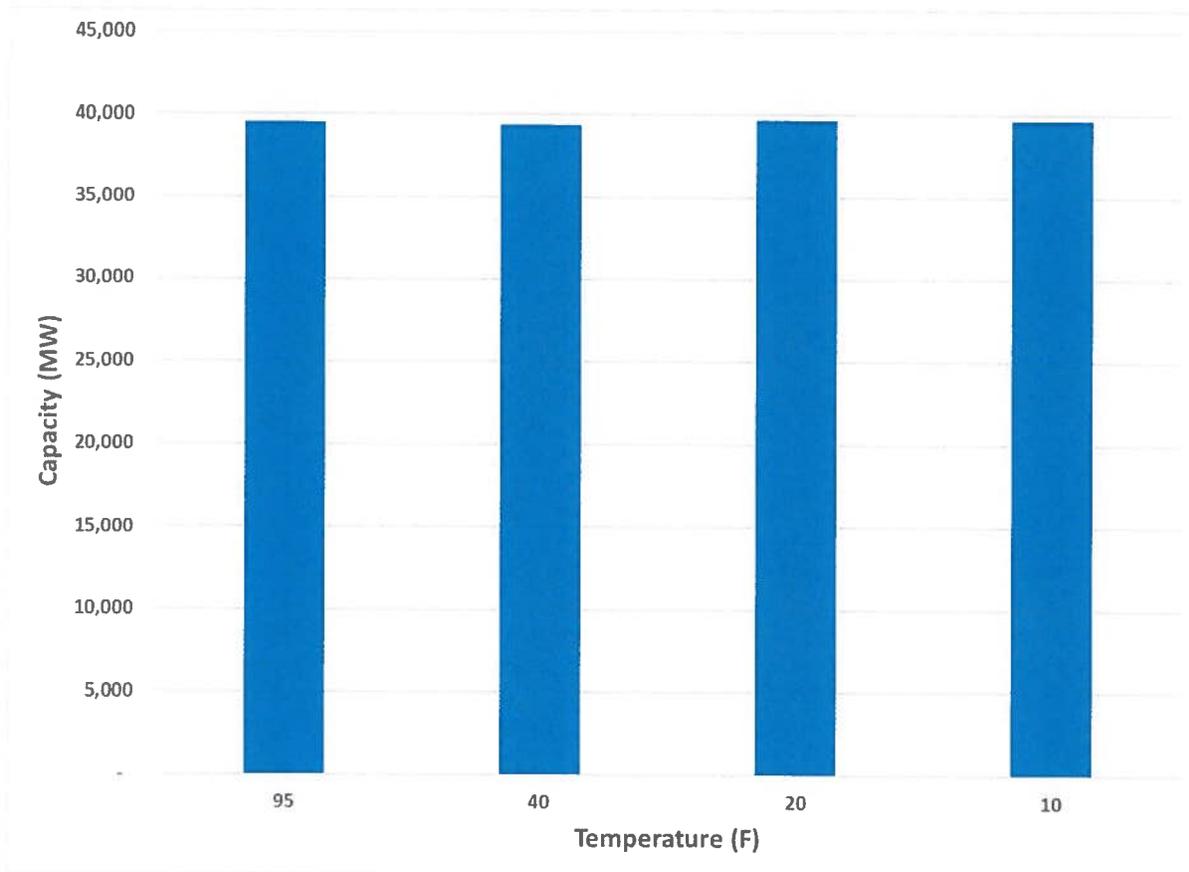
**Figure A. 13. Total Available Capacity by Temperature**

C.2 EUE by Season

Upon modeling these key drivers, the reliability model shows greater probability of EUE in the winter than has been previously shown. Figure A. 14 below shows the seasonal distribution of EUE at various (summer-oriented) reserve margins. The chart shows that at very low reserve margins, there is significant EUE in both the summer and winter periods. As reserve margin increases, the EUE in both the summer and the winter decreases. However, the EUE decreases much more rapidly in the summer than in the winter. In the winter, there is a probability of substantial EUE even at higher reserve margin levels. This is because the most extreme winter conditions in the model, while having a very low probability of occurrence, have a very high impact on EUE.

Southern Company
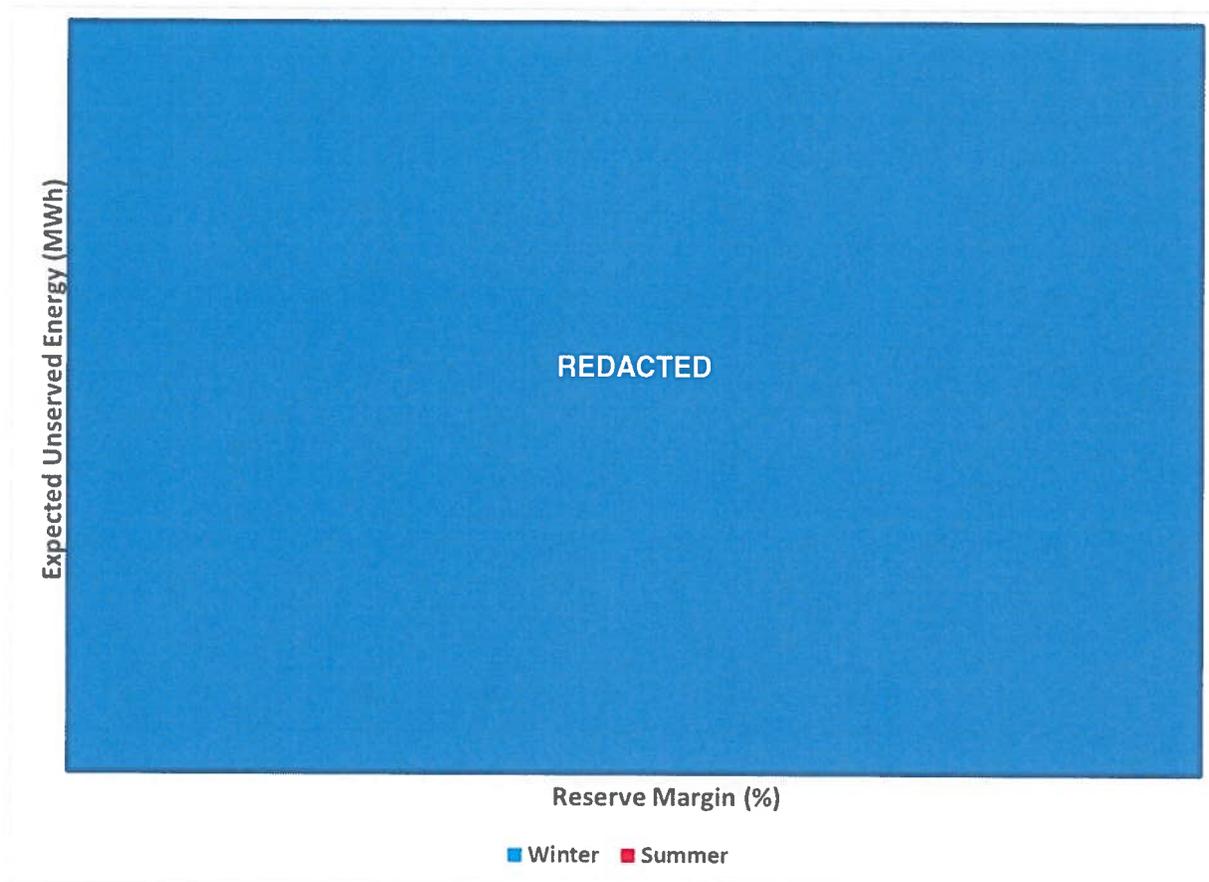
Figure A. 14. Seasonal EUE by Reserve Margin

C.3 LOLE by Season

Another way to view the relative risk between summer and winter is through the LOLE. LOLE, expressed in number of days of outage per year, shows the probability that an EUE event will occur in any given month or year. Therefore, while the EUE metric shows both the magnitude and probability of risk, LOLE focuses only on the probability of event, so it is not biased by the occurrence of large EUE events. The figure below shows the relative LOLE for both summer and winter. This chart demonstrates that at lower reserve margins, there is a significantly higher probability of a summer-related event, but at the higher levels, the probability of a winter-related event is greater. Taking Figure A. 14 and Figure A. 15 together, it can be concluded that the summer-related events are relatively small in magnitude while the winter-related events are very large in magnitude. Because the probability of those events remains even at high reserve margins, it becomes necessary to give particular attention to those winter-related risks.

Southern Company
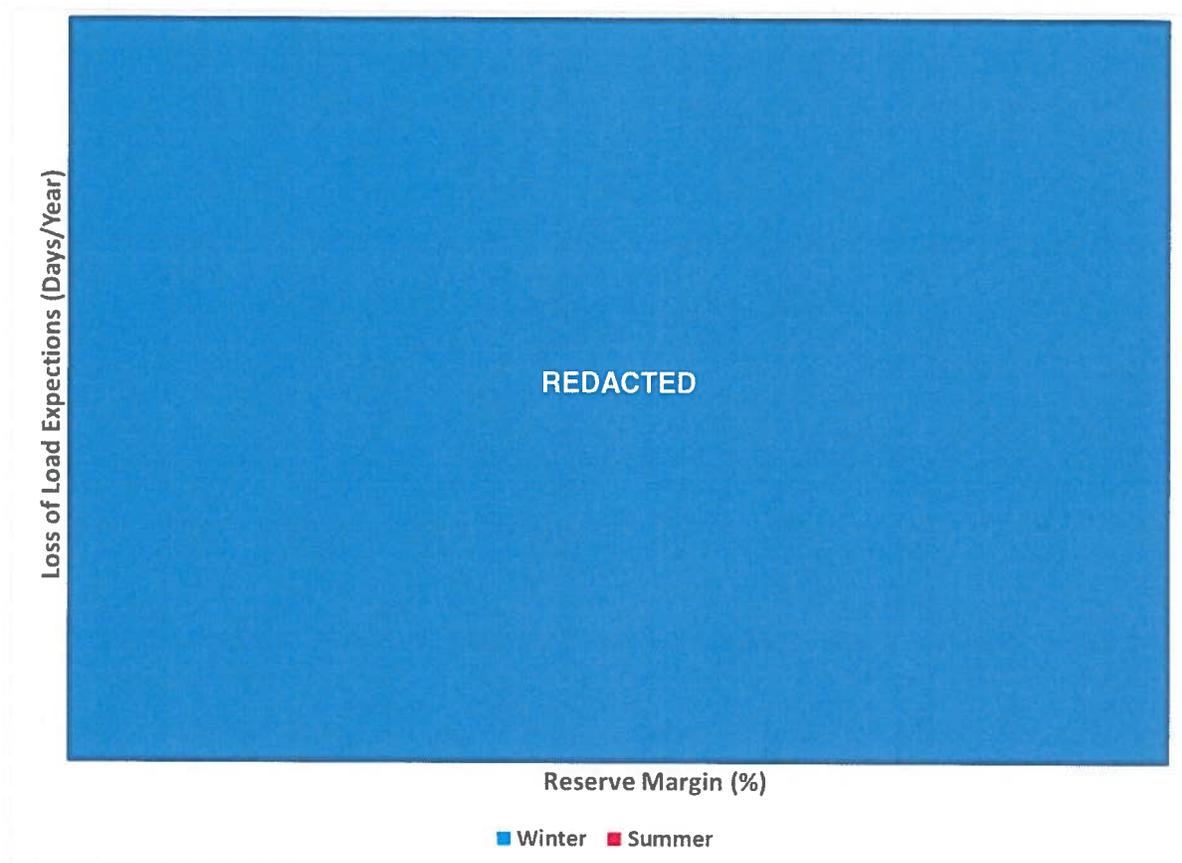
Figure A. 15. Seasonal LOLE by Reserve Margin

D. The Nature of the Winter Reserve Margin

Traditionally, reserve margins have been stated in terms of summer peak demands and summer capacity ratings as stated in the following formula:

$$TRM = \frac{TSC - SPL}{SPL} x\ 100\%$$

Where:

TRM = Target Reserve Margin;

TSC = Total Summer Capacity; and

SPL = Summer Peak Load.

Southern Company

This traditional representation is essentially a Summer TRM and has been the only reserve margin considered because the System (in aggregate) has always been, and remains, summer peaking on a weather-normal basis. These traditional reserve margins stated in summer terms have historically been in the 15-17% range.

However, reserve margins can just as easily be stated in alternate terms. In fact, the traditional Reserve Margin Study is based on an evaluation representing the simulation of an entire year – in fact thousands of alternative simulations of that one year. When the traditional reserve margin is calculated, what is being determined is a specific number of megawatts that are needed relative to peak load. Those megawatts include an underlying existing system (at a 10% reserve margin) and a certain number of reliability CTs added that represents the minimum total cost across the entire year. Once that has been established, a reserve margin can be calculated. That reserve margin is traditionally calculated based on a snapshot of a single hour in that year-long evaluation – the weather-normal summer peak against the official summer unit ratings. However, there are 8,760 hours in the case, each representing different load values and different amounts of total capacity because rated output of the resources in the case changes due to variations in temperature. Therefore, one could theoretically say there are 8,760 different reserve margins in that case – one for each hour of the year. Of present interest, however, are just the summer peak and the winter peak. Just as a summer reserve margin is a snapshot of the summer peak hour against summer capacity ratings, the winter reserve margin is a snapshot of the winter peak hour against the winter capacity ratings. That winter reserve margin is represented by the following formula:

$$Winter\ TRM = \frac{TWC - WPL}{WPL} x\ 100\%$$

Where:
TRM = Target Reserve Margin;
TWC = Total Winter Capacity; and
WPL = Winter Peak Load.

Because winter peak loads are different (lower for a summer peaking utility) than summer peak loads and because winter generating capacity can be different than summer generating capacity, the Winter TRM can be higher than the Summer TRM. The extent to which the Winter TRM is higher than the

Southern Company

Summer TRM depends on the relationship between the total available capacity in the summer versus the total available capacity in the winter as well as the differences in the weather-normal summer and winter peak loads. It is not out of the question for a Summer TRM of 15% or 16% to have an equivalent Winter TRM in the mid-to-upper 20s. **However, this Winter TRM represents both the same cost and the same level of reliability as its Summer TRM equivalent** – despite the appearances of being a "higher" reserve margin.

To illustrate this relationship, it is possible to take a snapshot of the System at a given moment in time and create a waterfall chart that demonstrates how to translate a summer reserve margin into a winter reserve margin. Figure A. 16 below illustrates this reserve margin translation from summer to winter. Reading the chart from left to right, a 16.25% summer reserve margin is based on summer total available capacity and the summer peak load. However, when moving from summer to winter there are various changes associated with increases or decreases in capacity. This is because some resources have higher capacity ratings in the winter versus the summer and others have lower capacity ratings in the winter versus the summer. Finally, there is a difference in the summer peak load and the winter peak load as well. In the example of Figure A.16, a 16.25% summer reserve margin is equivalent – that is, it has the same cost and the same level of reliability – to a 24.7% winter reserve margin.[23] In other words, if a Reserve Margin Study indicated the need for a 16.25% summer TRM, then it likely also indicated the need for a 24.7% TRM in the winter – especially if the study showed significant EUE potential in the winter.

---

[23] The 24.7% winter equivalent is based on the study case where the system is reduced to a summer reserve margin of 10% and restored to 16.25% using incremental CTs (consistent with how the Reserve Margin Study is performed).

Southern Company
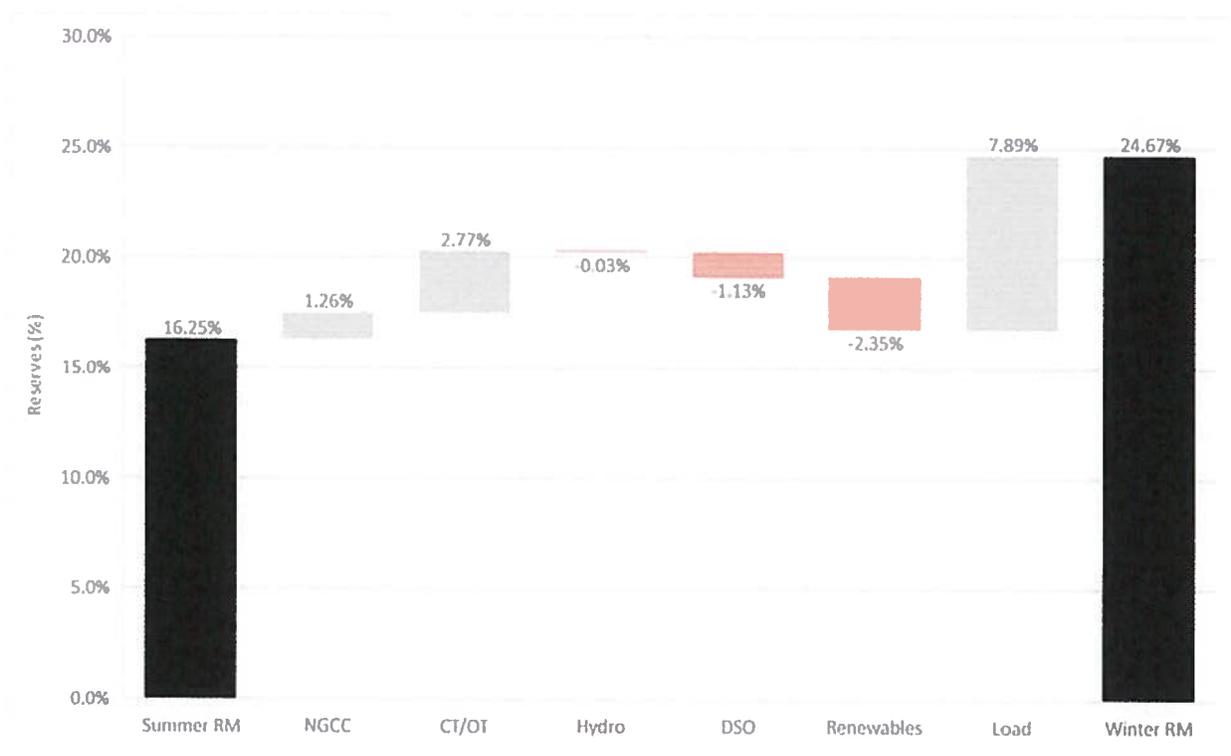
Figure A. 16. Winter Equivalent Waterfall

It should be carefully noted, however, that this waterfall chart is based on a snapshot in time. If anything changes on the System that changes the relationship between summer and winter, this equivalency changes.

E. Resulting Need for Winter Target Reserve Margin ("TRM")

Because the equivalency between summer and winter can change depending upon System conditions, it would be dangerous to only consider the summer TRM of 16.25% when planning the System and presume the winter will always have the necessary 24.7%. For example, if a coal unit were retired and replaced with a CC of equal summer capacity, the winter reserve margin would be higher than 24.7%. This is because a coal unit has the same ratings for both summer and winter while a CC may have more capacity in the winter. Similarly, if a CT were retired and replaced with a solar facility, the winter reserve margin would be lower than 24.7% because the CT has higher capacity in the winter relative to summer, but a solar facility's capacity contribution is less in the winter. Likewise, if the winter peak load forecast increased relative to the summer, the winter reserve margin would be lower than the 24.7%.

Southern Company

This changing winter equivalency phenomenon can be demonstrated by examining how the winter equivalent of the currently approved 16.25% TRM (a summer-oriented value) has changed since the 2015 Reserve Margin Study. The 2015 Reserve Margin Study first introduced some of these winter reliability risks as the reason for the increase in reserve margin at that time from 15% to 16.25%. The winter equivalent of 16.25% from that study – if it would have been calculated at that time – would have been 26% for a study year of 2019.[24] That reliability case was based upon Budget 2016. When reliability cases were updated for Budget 2017, the study year was moved to 2024 and the winter equivalent of 16.25% reduced from 26% to 25.6%.[25] When reliability cases were updated for Budget 2018, the study year was moved from 2019 to 2025; and the winter equivalent of 16.25% dropped again to the 24.7% shown in Figure 16 above. However, that 24.7% is based upon the theoretical situation in which the System is reduced to 10% and restored to 16.25% using incremental CTs. The actual winter equivalent of the existing system if it were reduced from its current state down to 16.25% would only be 23.7%. In other words, if planners only evaluate the system using the 16.25% Summer TRM, they could be misled into believing the system had adequate reliability in the winter (i.e., the presumed 26% winter equivalent required by the 2015 Reserve Margin Study) when the reality would be that the System only had 23.7% in the winter. This could lead to an unexpected and unforeseen reliability event in the winter such as what happened with the Polar Vortex event of 2014.

The Reserve Margin Study identifies the amount of reserves needed to maintain the proper economic and reliability balance in both the summer and winter seasons. It is the requirement identified by the study, not the changing equivalence, that should be considered as part of the planning process. Only considering the Summer TRM from the study essentially plans to the changing equivalence, not the requirement identified in the study, which could be misleading. Therefore, it is necessary to calculate both the Summer TRM and the required Winter TRM and then monitor and plan to both accordingly.

---

[24] This winter equivalent is based on reducing the system to 10% and restored to 16.25% using incremental CTs.
[25] This winter equivalent is based on reducing the existing system down to 16.25%; reducing the system to 10% and restoring with incremental CTs would result in a winter equivalent of 26.5%.

Southern Company

F. Conclusion

In conclusion, when the determinants and the resulting impact on seasonal reliability are carefully considered, continuing to plan the System using only a single (summer-oriented) TRM will increase the likelihood of an unforeseen loss of load event like the one that occurred in January 1977 and like what could have happened in January 2014. Therefore, while it may not be possible or cost-effective to completely eliminate the possibility of a winter loss of load event, it is necessary to establish and plan the System on a seasonal basis, with both a Summer TRM and a Winter TRM, to provide the appropriate level of mitigation against such risks.

Southern Company

Appendix B – Capacity Worth Factors

A. Background

Capacity Worth Factors ("CWFs") represent the relative worth of capacity from one period to another (*i.e.*, hour, month, season, etc.). As such, they represent the relative risk of a reliability event from one period to another. CWFs are developed hourly using the SERVM reliability model and from that model, represent the hourly improvement in reliability associated with a "perfect" megawatt (i.e., a megawatt that is available every hour of the year). CWFs can be represented hourly or they can be aggregated and represented monthly or even seasonally. CWFs are calculated at the Target Reserve Margin and so are a downstream output of the Reserve Margin Study and the associated approved Target Reserve Margin.

CWFs in some form are used in almost all System-wide analyses when deriving capacity value, including:

- IIC reserve sharing,
- PRICEM analyses,
- Retirement studies,
- Power Purchase Agreements,
- ICE Factors for the IRP, and
- Renewable Cost Benefit Analyses.

B. The SERVM Reliability Cost Report

The Capacity Worth Factor Table ("CWFT") is derived from the Reliability Cost report produced by the SERVM model. The Reliability Cost report generates the weighted sum of:

(a) the cost of EUE, plus
(b) the cost of expected Reliability Purchases, plus
(c) the cost of any Spinning, Supplemental, or Regulating Reserve shortfall.

Unlike the Reserve Margin Study, when calculating the CWFT, the Company is not interested in cost impacts, but rather in reliability impacts. Therefore, the CWFT is calculated only considering the

Southern Company

probability and magnitude (not cost), resulting in a MW-weighting of the potential events identified above. To accomplish this, these events are all modeled with equal costs so that the Reliability Cost report is effectively only weighting these components based on MW impact, not relative cost, using the following modeling techniques:

- Reliability Purchases (defined as any purchase that avoids EUE) are determined by running the SERVM simulation as a "Southern-Only" case; this eliminates the model's ability to make reliability purchases which, in effect, treats Reliability Purchases as EUE.
- Spinning, Supplemental, and Regulating Reserves are modeled such that load will be curtailed to prevent a shortfall, thus also valuing those shortfalls as EUE.

Figure B.1 below shows all reliability components and which ones are included in the Reliability Cost report as inputs into the CWFT calculation.

Load Serving Components in SERVM

Total Expected Load

UE	Weighted by MW (includes load curtailment to maintain RR & SR)
OR	Weighted by MW
DR	Not included in CWFT Calculation
RP	Weighted by MW
G	Not included in CWFT Calculation

UE ≡ Unserved Energy
OR ≡ Operating Reserve Shortfall
DR ≡ Demand Response Calls
RP ≡ Reliability Purchases
G ≡ Production Cost (including economic purchases)
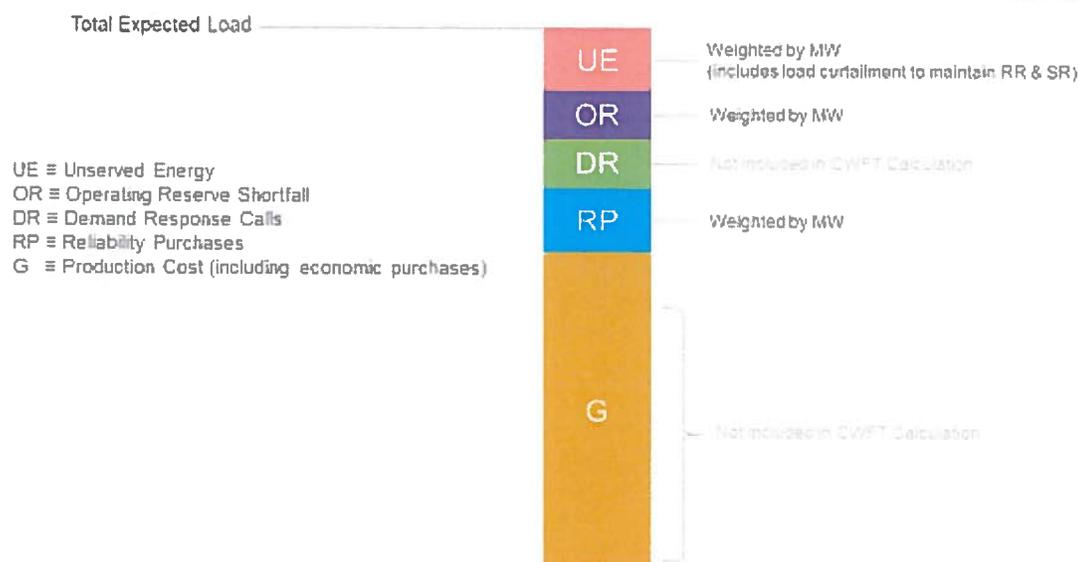
Figure B. 1 Treatment of Reliability Components in the CWFT Calculation

The Reliability Cost report can be generated using a combination of EUE Capacity, EUE IntraHour, EUE MultiHour, Net Purchases, and Production Cost. To generate the appropriate CWFT using this

Southern Company

methodology, the Reliability Cost report is generated using EUE Capacity, EUE Intra-Hour, and EUE Multi-Hour (not Net Purchases and not Production Cost).

C. Capacity Worth Factor Results

CWFs are updated with each budget cycle. The 2018 Reserve Margin Study was performed using Budget 2018 ("B2018") vintage data for inclusion in the 2019 IRP. CWFs resulting from the 2018 Reserve Margin Study will not be officially available until after the Budget 2019 ("B2019") Reliability Base Case has been developed and so should be available in the first quarter of 2019. However, a 12x24 representation of the CWFs associated with the B2018 vintage data are shown in Tables B.1 and B.2 below.

Table B.1 shows the CWFT assuming the currently approved 16.25% TRM without Seasonal Planning.

Table B. 1 B2018 Vintage CWFT at 16.25% Summer TRM (Central Prevailing Time)

Southern Company

Table B-2 shows the B2018 Vintage CWFT assuming the approval of the proposed 26% Winter TRM.

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11						REDACTED						
12												
13												
14												
15												
16												
17												
18												
19												
20												
21												
22												
23												
24												

Table B. 2 B2018 Vintage CWFT at 26% Winter TRM (Central Prevailing Time)

These tables will change once the Reliability Base Case has been updated for B2019 vintage planning assumptions. Furthermore, Table B-2 should be considered preliminary and indicative only. Table B-2 as shown above has not been used for the purposes of evaluating any renewable resource or any other resources.

Because the 26% Winter TRM is the dominant factor for System reliability, upon approval of seasonal planning, the official CWFT for the System will be the CWFT associated with the 26% Winter TRM.

Southern Company