PUBLIC DISCLOSURE

An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System

January 2022

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 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, 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 2021 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 near term capacity decisions, with subsequent re-evaluations modifying downstream decisions, as appropriate.

This report recommends Winter and Summer TRMs stated in terms of seasonal peak demands and seasonal capacity ratings according to the following formula:

$$TRM_S = \frac{TC_S - PL_S}{PL_S} x\ 100\%$$

Where:
TRM_S = Seasonal Target Reserve Margin;
TC_S = Total Seasonal Capacity; and
PL_S = Seasonal Peak Load.

The 2018 Reserve Margin Study exposed winter reliability concerns not captured in previous studies. These concerns persist in the 2021 Reserve Margin Study. Because winter peak loads are different than summer peak loads (lower for a summer peaking utility in normal weather conditions but more volatile) and because winter generating capacity can have different operational characteristics than summer generating capacity, the Winter TRM can be higher than the Summer TRM. Additionally, most resources on the system are capable of dispatching annually and not restricted to only winter months. Taking this into consideration, the Company's evaluation considers the Loss of Load Expectation ("LOLE") in each season. The Reserve Margin Study recommendation ensures that the combined seasonal LOLEs equate to an annual LOLE at or above a one event in ten years threshold ("1:10 LOLE").

Reserve Margins are necessary because of uncertainties in operational conditions. The four primary uncertainties influencing the TRM 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 14.9% higher in a hot summer year and 19.6% higher in a cold winter year 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) **Load Forecast**: 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 projection to actual variances, peak demand may grow by 4.9% 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]

[1] See Figure I.3 in Section I.
[2] See Table I-3 in Section I.
[3] See Figure I.8 in Section I.

4) **Market Availability Risk**: The ability to obtain resources from the market when needed to address a short-term System resource adequacy issue can vary. 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 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 a minimum reliability criteria threshold. Common practice in the industry regarding this minimum reliability criteria threshold is to plan for a LOLE of no greater than 0.1 days per year - or 1:10 LOLE.

To understand and quantify the overlap of the four contributing factors to the need for reserve margins, the Strategic Energy and Risk Valuation Model ("SERVM") was 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 winter planning reserve margins from 20% - 32%. 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 winter reserve margin of 24.25%. The figure represents the weighted average costs over all the load, weather, and outage draws simulated and is stated in terms of the winter-oriented reserve margin.[4]

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

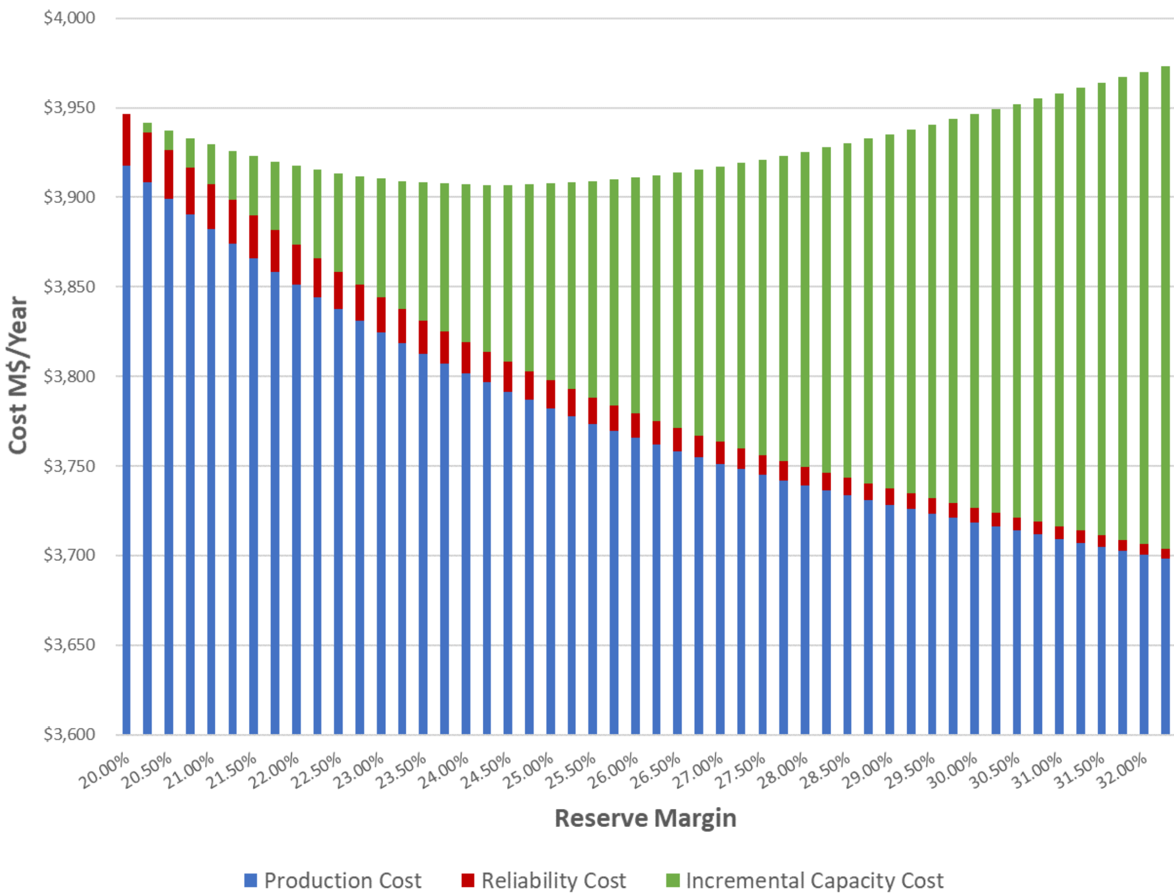

Figure 1. Winter EORM U-Curve

Since winter is the driving factor, represented by the Winter TRM, an analysis was performed to determine what a Summer TRM would be assuming the removal of the winter months January, February, and December from the economic analysis. The results of this analysis show that the EORM for the Summer TRM is 20.50%. This value is closer to the Winter TRM in the 2021 Reserve Margin Study than in past studies due to the narrowing of the gap between the weather-normal seasonal peak loads.

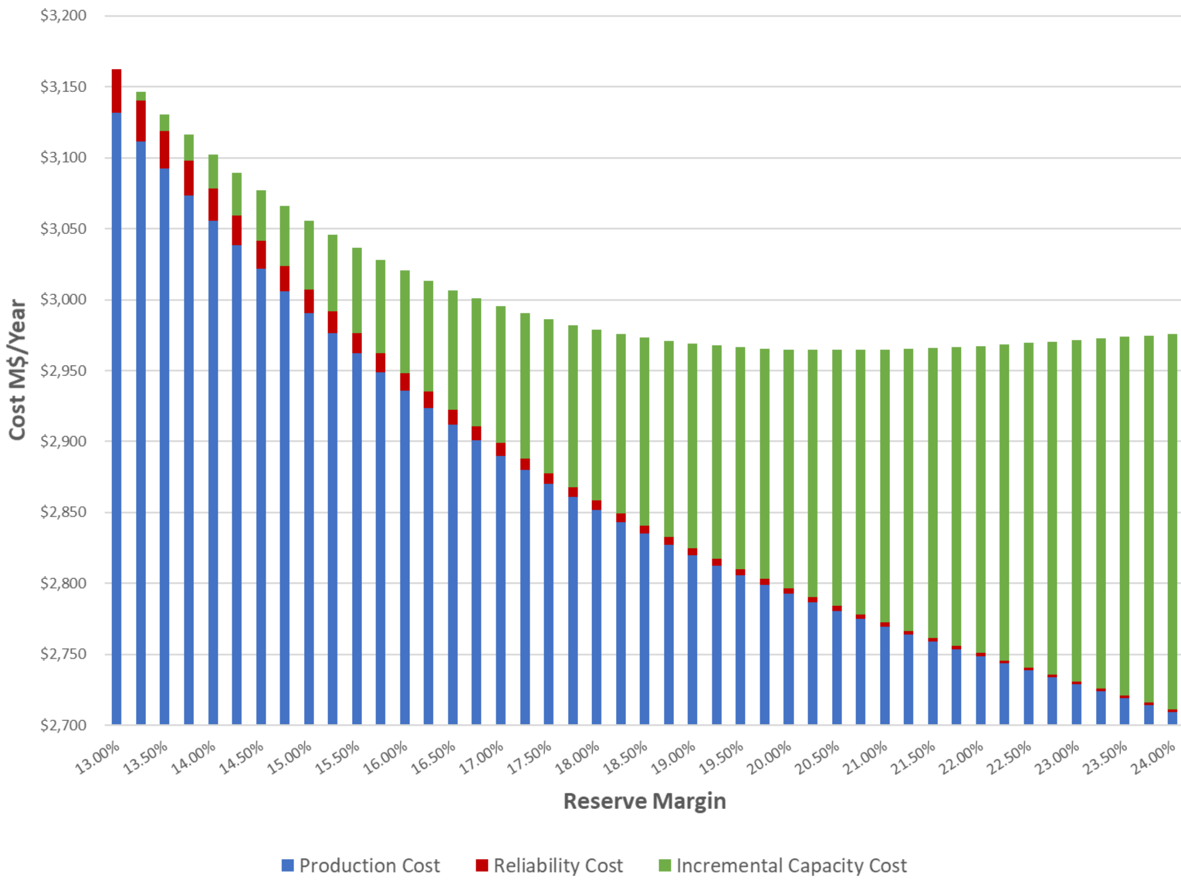

Figure 2. Summer EORM U-Curve

These two U-Curves and their associated analyses serve as the basis for determining a recommendation for the Winter and the Summer TRMs. Since winter is the constraining season for reliability on the System due to additional winter-only reliability concerns, the Winter TRM was considered first.

While the minimum cost of the winter U-Curve falls at 24.25%, 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 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 a 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 85th 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[5] 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 75th confidence interval up to the 95th confidence interval, using 0.25% reserve margin increments.

The adjusted EORM at each confidence interval can be demonstrated graphically by developing their respective U-Curves which represent the sum of the expected cost and value at risk for each reserve margin level. Figure 3 below shows that if the U-Curve is drawn at each confidence interval from the 75th to the 95th, this adjusted EORM is higher than the expected case EORM, 24.25%. 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.

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

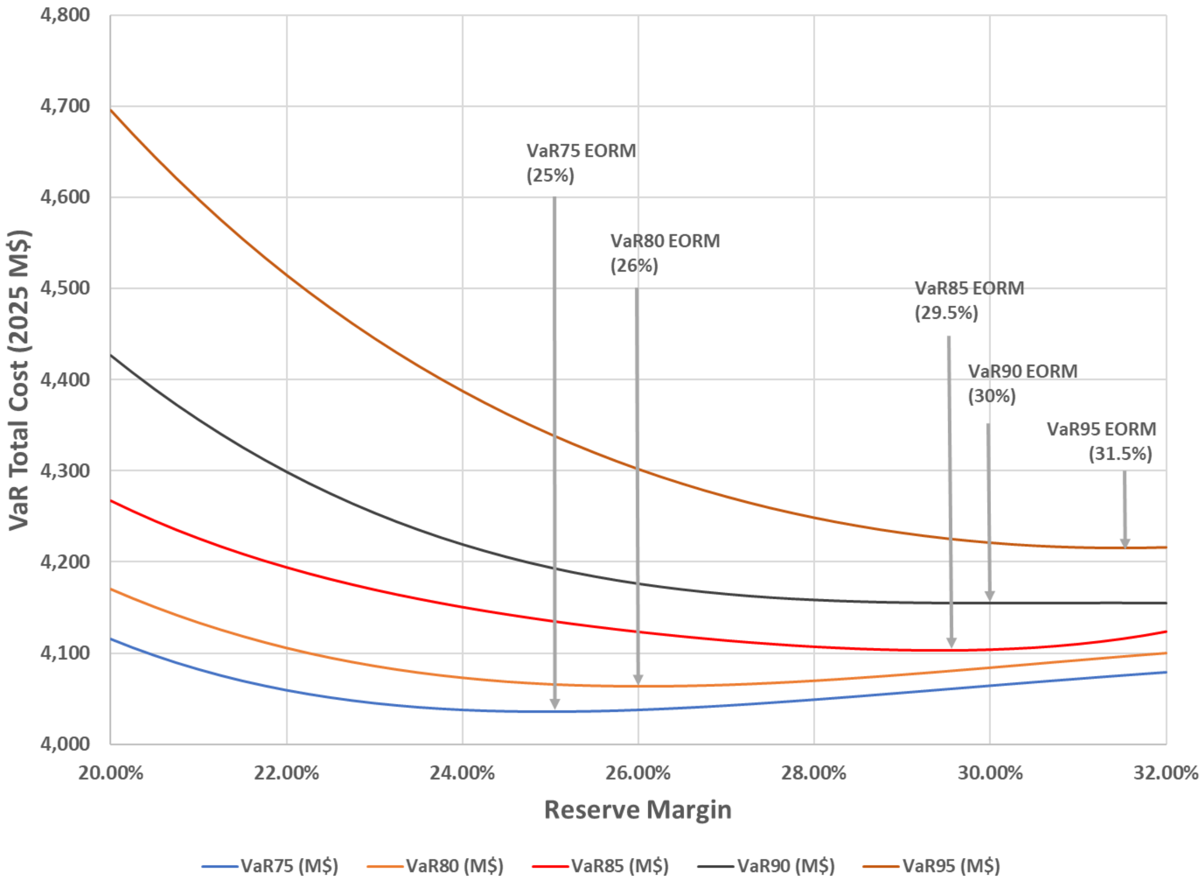

Figure 3. Confidence Interval U-Curve (Winter)

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 a LOLE threshold of 0.1 days per year (or often referred to as a one event in ten year expectation of loss of load). LOLE has always been considered as part of the reserve margin studies and for the 2021 Reserve Margin Study, the 1:10 LOLE threshold is below the respective winter and summer study EORM values.

Figure 4 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 20.00% 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 generation shortfalls more frequently than customers in other regions of the country.

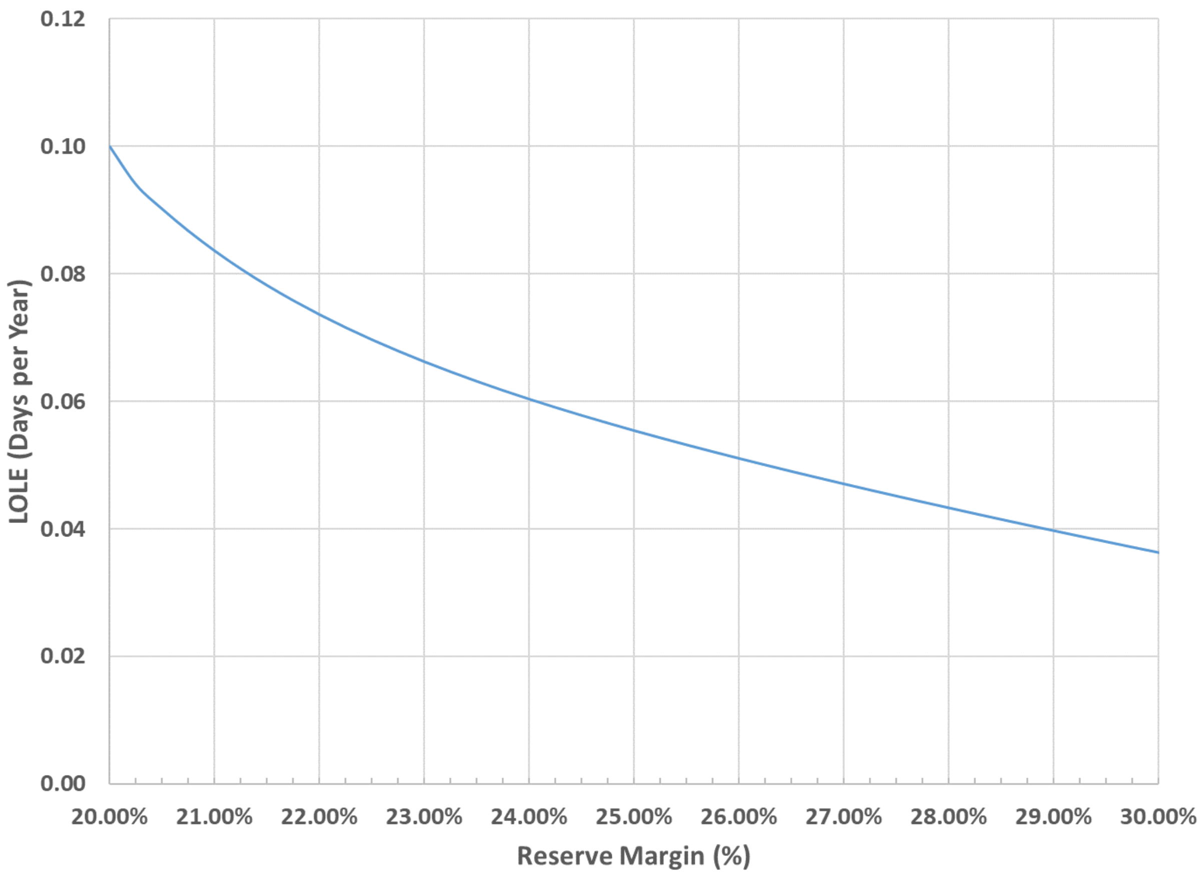

Figure 4. LOLE as a Function of Winter Reserve Margin

The 2021 Reserve Margin Study recommends a long-term Winter TRM of 26% based on the following:

1. The TRM should be greater than the 20.00% 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 that falls within the confidence intervals considered;
3. Compared to the 24.25% expected case EORM, a 26.00% risk-adjusted EORM reduces VaR at the 85th confidence interval by $27.2M/year, while only increasing expected cost by $4.1M/year;
4. Compared to the 20.00% 1:10 LOLE threshold, a 26.00% risk-adjusted EORM reduces VaR at the 85th confidence interval by $108.8M/year and reduces expected cost by $35.1M/year; and
5. A 26% Winter TRM is consistent with results from the 2018 Reserve Margin Study.[6] Maintaining this TRM provides stability to the integrated resource planning process.

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 20.50%, the VaR85 calculation resulted in a reserve margin of 23.25%. Therefore, a Summer TRM of up to 23.25% could be justified based on this case. LOLE must also be considered. If resources added to the System are available in both the winter and the summer, the LOLE will be as shown in Figure 4. However, if some of 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 the total combined summer and winter LOLE does not fall below the 1:10 LOLE threshold ("Summer TRM Floor"). Figure 5 below shows the 1:10 LOLE threshold Summer TRM Floor for various Winter TRM values.

[6] In the 2018 Reserve Margin Study, "An Economic Study of the System Planning Reserve Margin for the Southern Company System" (January 2019), the recommended Winter TRM was 26%.

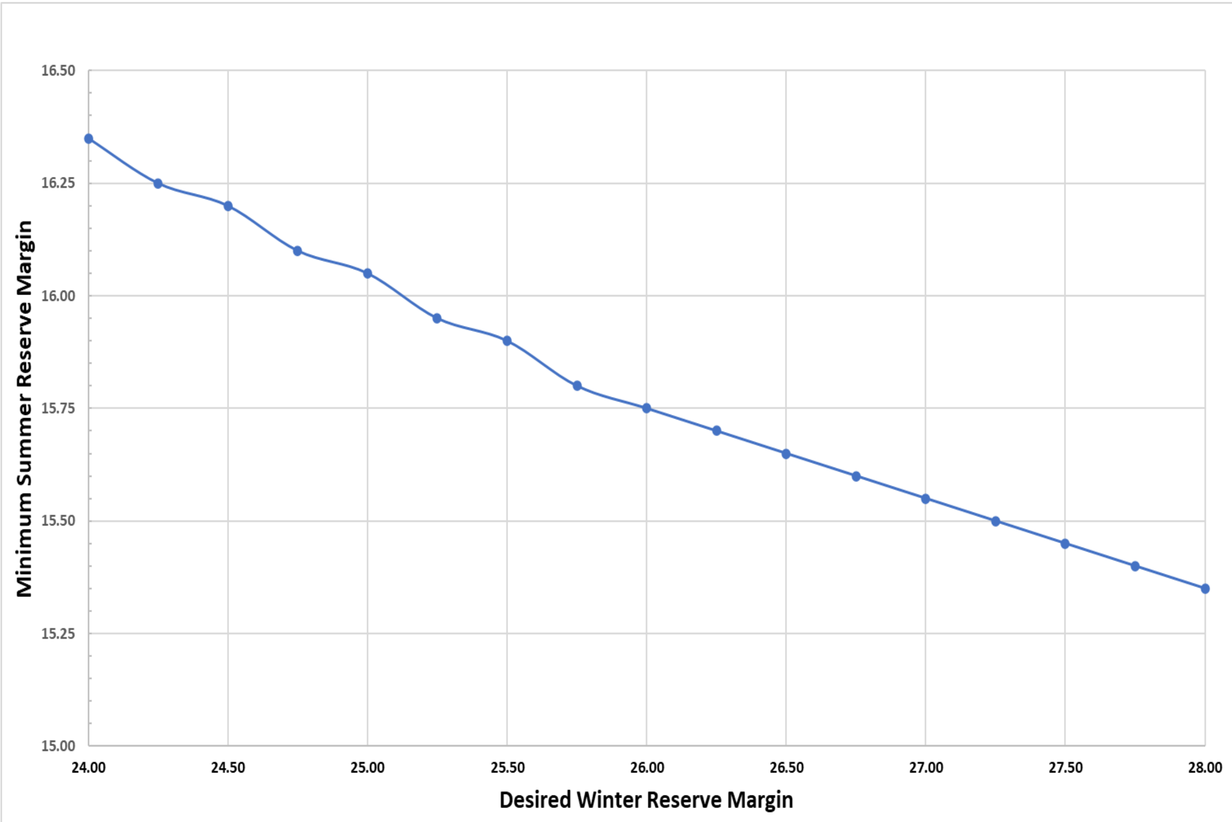

Figure 5. Summer Target Reserve Margin Floor

Based on Figure 5, the Summer TRM Floor for the recommended Winter TRM of 26% must be at or above 15.75% to ensure the combined LOLE does not fall below the 1:10 LOLE. Although the economic results of the study could justify a summer TRM of at least 20.50%, it is not recommended to increase the summer TRM at this time. This is because the combination of the 26% Winter TRM and 16.25% Summer TRM provides an adequate level of reliability and increasing the TRM in the summer would have little impact on the planning process, as winter is the driving season. It is therefore 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 decisions that result in reserve margins above or below the specified targets due to the large size of capacity additions, the availability and price of market capacity, or economic changes.

RECOMMENDATIONS:

1. Maintain current approved TRM of 16.25% as the Summer TRM
2. Maintain current approved TRM of 26.00% as the Winter TRM
3. Apply a short-term reserve margin that is 0.5% lower than the long-term reserve margins

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I. ASSUMPTIONS

The following sections of this report provide detailed discussions related to the input assumptions associated with the 2021 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, in a partial forced outage, full forced outage, or on scheduled maintenance. The total capacity online and available to serve load is calculated and compared to the hourly 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.

Throughout the simulation, SERVM perfectly matches load and generation. During actual EUE events, load would be curtailed in large blocks and might be off longer than modeled in SERVM. Modeling load curtailment in this way would increase the expected EUE and the EORM. As such, the results of the 2021 Reserve Margin Study do not represent the most extreme outcome possible.

B. Study Year

To perform the analyses necessary for the 2021 Reserve Margin Study, a study year was selected that corresponds with the current year plus four. Since reserve margin studies are performed every three years, this ensures that the reserve margin study year is always forward looking compared to the current integrated resource plan budget year. 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 58 historical annual weather patterns from 1962 through 2019. These 58 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 pattern matched that of one of the historical years. Two annual load shapes were developed for each of the 58 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 occur either on the weekend or on a weekday. These 116 datasets or “weather years” were given equal probability of occurrence.

The weather year load shapes were developed by using a forecasting model to establish the relationship between the weather and load. The model was calibrated using weather and load data for the years 2014 through 2019 so that more recent customer usage patterns are reflected. The calibrated model was then used to construct the 116 weather year load shapes using the 58 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 58 weather years modeled.

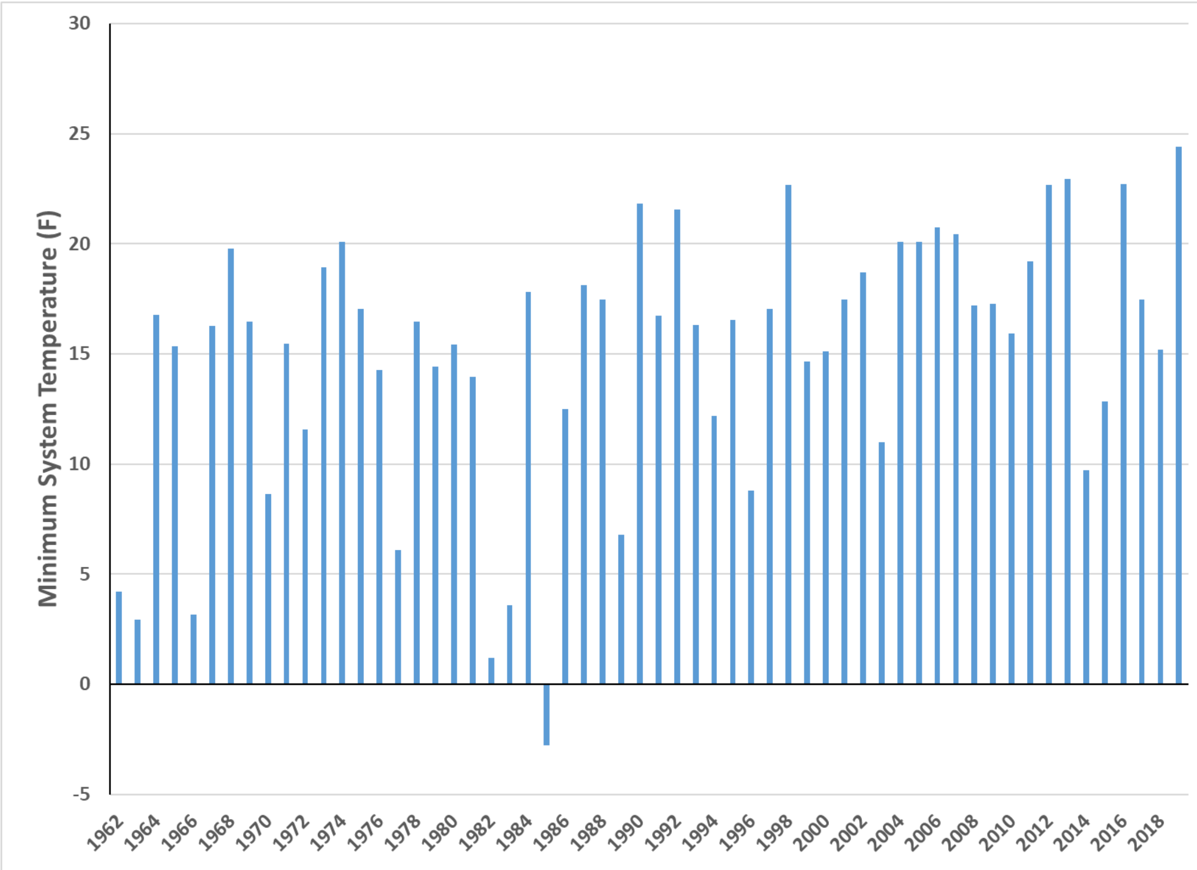

Figure I.1. Historical Low Winter Temperatures

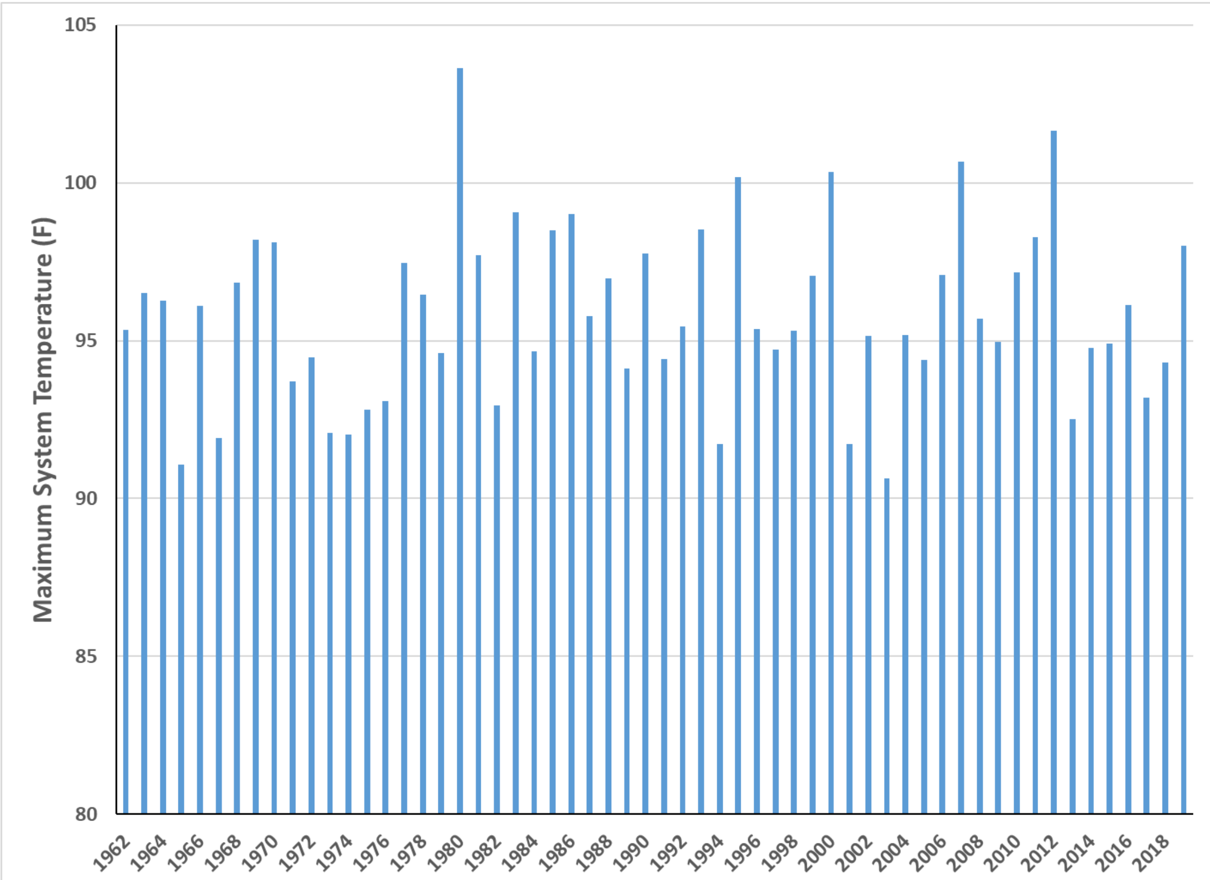

Figure I.2 Historical High Summer Temperatures

The final load shapes can also be used to show a probability distribution around the forecasted weather-normal peak loads. This distribution is determined by the expectation of non-weather-normal conditions, represented by the 116 modeled load shapes. Figure I.3 below shows the distribution or peak volatility for each season.

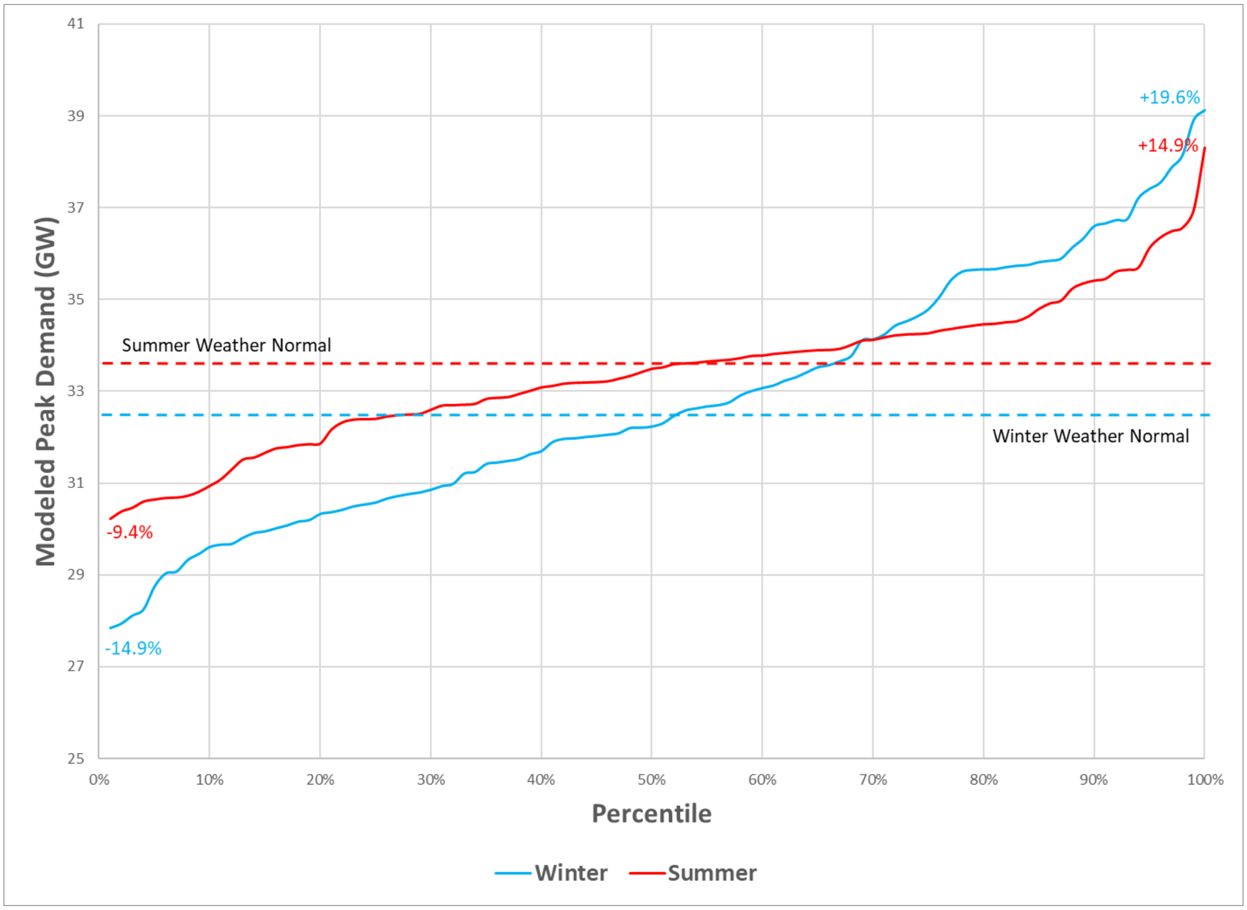

Figure I.3 Distribution of Modeled Summer and Winter Peak Loads

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 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 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 system 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)	Average Transfer Capability into Southern Company System (MW)	CBM[7] into Southern Company System (MW)
TVA	28%	29682	679	250
Duke Energy Carolina	22%	22019	186	300
SCEG	30%	4942	109	-
Santee Cooper	36%	4663	443	-
FPL	15%	25760	110	100
Progress FL	19%	9472	102	50
JEA	48%	2750	36	100
TAL	55%	614	15	-
PowerSouth	20%	2450	1606	-
Progress Carolinas	43%	13104	-	-
MISO-South	24%	33267	2119	250
OPC	26%	10496	Unlimited	-
MEAG	54%	2112	Unlimited	-
Gulf	55%	2590	1700	-

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

Table I-2. Simulation Regions Summary for Winter

Region Name	Winter Reserve Margin Modeled (%)	Peak Load (MW)	Average Transfer Capability into Southern Company System (MW)	CBM[8] into Southern Company System (MW)
TVA	28%	30171	1618	250
Duke Energy Carolina	27%	20993	461	300
SCEG	26%	5022	162	-
Santee Cooper	29%	5181	531	-
FPL	48%	20756	96	100
Progress FL	18%	10100	88	50
JEA	44%	3025	32	100
TAL	75%	569	13	-
PowerSouth	59%	2005	1481	-
Progress Carolinas	28%	14475	-	-
MISO-South	42%	28278	1757	250
OPC	37%	9809	Unlimited	-
MEAG	67%	1957	Unlimited	-
Gulf	49%	2349	1700	-

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

The topology used for the simulations is in Figure I.4.

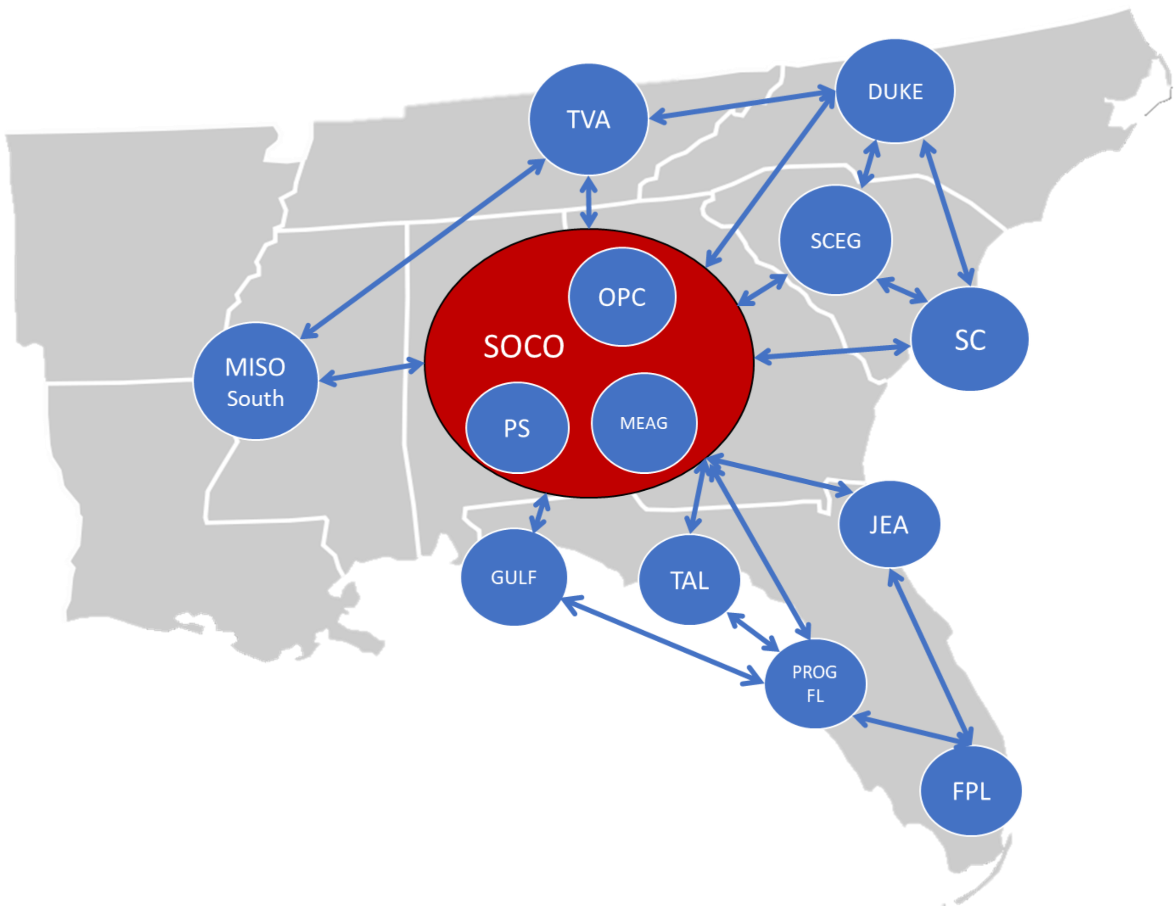

Figure I.4. Simulation Topology

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.

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 (2012-2019) of historical market purchases to estimate the market purchase cost in scarcity scenarios and is shown in Figure I.5 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 energy market price.

REDACTED

Figure I.5. Scarcity Pricing Curve

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, Florida Power and Light, Progress Florida, and JEA totaling 1,050 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 Commercial Operations organization has advised that under extremely high summer load conditions, the availability of purchases in the marketplace is unlikely to exceed 2,200 MW. Likewise, under extremely high winter load conditions, the availability of purchases in the marketplace is unlikely to exceed 2,000 MW. 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, in which case 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. Peak Load Forecast

Unlike simulations performed in the 2018 Reserve Margin Study and prior, the 2021 Reserve Margin Study was performed with seasonal peak load. The model adjusted weather year load shapes based on the seasonal peak load values entered. The following 2025 System Peak Load values were used for all primary and sensitivity studies: 28,331 MW (Spring), 33,346 MW (Summer), 32,710 MW (Winter), and 25,627 MW (Autumn).

On a weather-normal basis, the System remains a slightly summer peaking utility. However, the gap between the weather-normal summer peak load and the weather-normal winter peak load has narrowed in recent years. Figure I.6 below shows the one-year ahead forecasted peak loads since 2006 as well as the Budget 2021 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 6,600 MW to less than 650 MW.

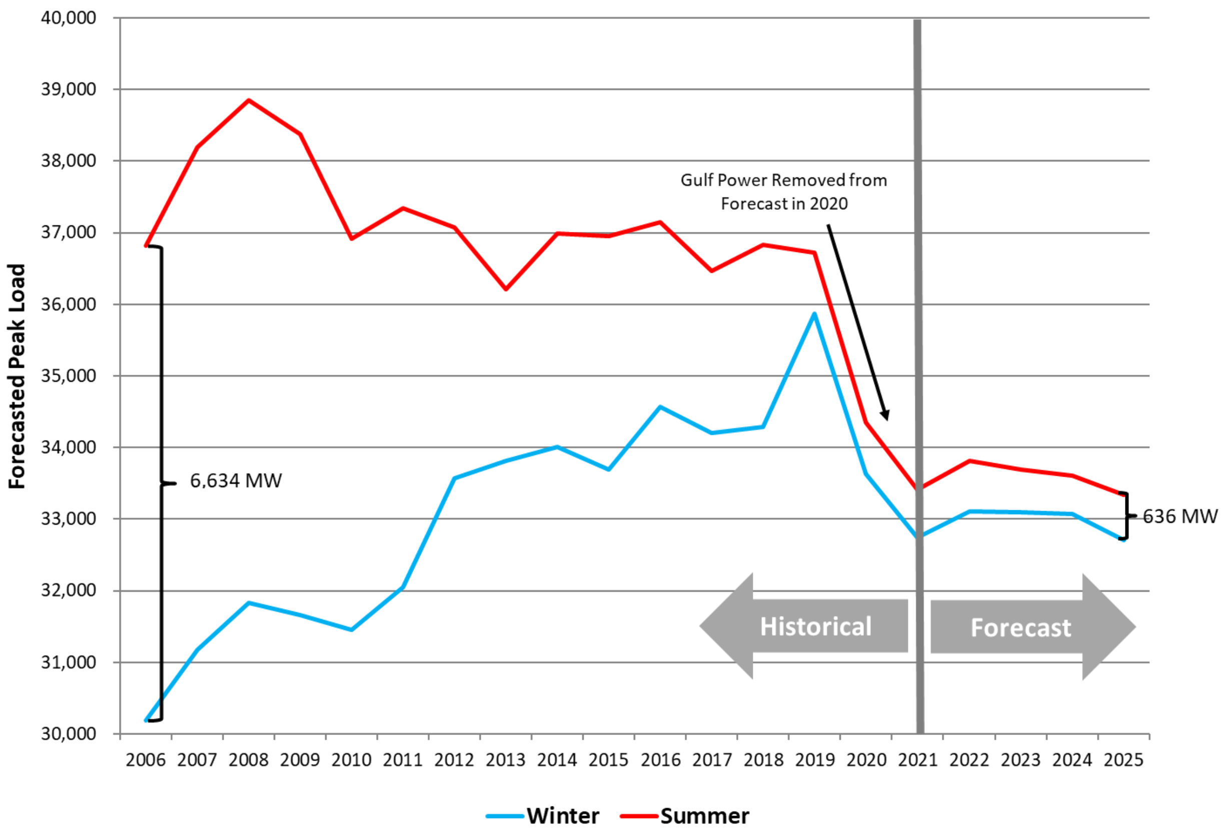

Figure I.6. Historical Forecasted Weather Normal Peak Loads

F. Load Forecast Uncertainty

In addition to variation from normal weather, uncertainty remains in the peak load projections when looking several years into the future. If load grows more quickly than expected, the reserve 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"). Unforeseen changes in electricity utilization and technology (*e.g.,* heat pumps, electric transportation, and energy efficiency) are also sources of LFE. Lastly, the regression and simulation models used to estimate loads have unavoidable inherent error. No mathematical model captures all variability in the estimation. This modeling error is expressed as the model margin of error. All of these sources of uncertainty are contained in the realized LFE that occurred historically.

The LFE assumptions used in the 2021 Reserve Margin Study were updated in the spring of 2021. Load forecast uncertainty four years into the future was estimated using 18 years of historical forecast vintage data from 2000-2017. Percent difference between the 4^{th} year energy projections and the weather normal energy actuals was determined for each forecast year and sorted from smallest to largest. The median or 50^{th} percentile variance was then used to re-center all forecast error data points. This resulted in a maximum under-forecast error of -4.93% (load being 4.93% higher than expected) and a maximum over-forecast error of 6.49% (load being 6.49% lower than expected). Each of the 18 LFEs has a 5.56% (1/18) chance of occurring. By combining and averaging the LFEs in a bell curve distribution, the 18 LFE points were converted to five LFE points as shown in the following table. For example, points 2 (LFE = -4.00%), 3 (LFE = -2.44%), 4 (LFE = -1.85%), and 5 (LFE = -1.44%) were combined and averaged to yield -2.44%, and the combined probabilities were summed to achieve a combined probability of 22.22% (4*0.05556 = 0.2222). This was done to minimize the total number of runtime simulations that would be required while still considering a distribution of LFE possibilities.

Table I-3. Load Forecast Error

<table>
<tr><th></th><th colspan="4">18 LFEs</th><th colspan="2">5 LFEs</th></tr>
<tr><th></th><th>Actual LFE</th><th>Median</th><th>Centered LFE</th><th>Probability</th><th>LFE</th><th>Probability</th></tr>
<tr><td>1</td><td>1.36%</td><td>6.29%</td><td>-4.93%</td><td>5.56%</td><td>-4.93%</td><td>5.56%</td></tr>
<tr><td>2</td><td>2.28%</td><td>6.29%</td><td>-4.00%</td><td>5.56%</td><td rowspan="4">-2.44%</td><td rowspan="4">22.22%</td></tr>
<tr><td>3</td><td>3.84%</td><td>6.29%</td><td>-2.44%</td><td>5.56%</td></tr>
<tr><td>4</td><td>4.43%</td><td>6.29%</td><td>-1.85%</td><td>5.56%</td></tr>
<tr><td>5</td><td>4.85%</td><td>6.29%</td><td>-1.44%</td><td>5.56%</td></tr>
<tr><td>6</td><td>5.02%</td><td>6.29%</td><td>-1.27%</td><td>5.56%</td><td rowspan="8">0.00%</td><td rowspan="8">44.44%</td></tr>
<tr><td>7</td><td>5.48%</td><td>6.29%</td><td>-0.81%</td><td>5.56%</td></tr>
<tr><td>8</td><td>6.13%</td><td>6.29%</td><td>-0.16%</td><td>5.56%</td></tr>
<tr><td>9</td><td>6.15%</td><td>6.29%</td><td>-0.14%</td><td>5.56%</td></tr>
<tr><td>10</td><td>6.42%</td><td>6.29%</td><td>0.14%</td><td>5.56%</td></tr>
<tr><td>11</td><td>6.44%</td><td>6.29%</td><td>0.15%</td><td>5.56%</td></tr>
<tr><td>12</td><td>7.14%</td><td>6.29%</td><td>0.85%</td><td>5.56%</td></tr>
<tr><td>13</td><td>7.50%</td><td>6.29%</td><td>1.21%</td><td>5.56%</td></tr>
<tr><td>14</td><td>8.39%</td><td>6.29%</td><td>2.10%</td><td>5.56%</td><td rowspan="4">4.31%</td><td rowspan="4">22.22%</td></tr>
<tr><td>15</td><td>10.31%</td><td>6.29%</td><td>4.03%</td><td>5.56%</td></tr>
<tr><td>16</td><td>11.18%</td><td>6.29%</td><td>4.89%</td><td>5.56%</td></tr>
<tr><td>17</td><td>12.49%</td><td>6.29%</td><td>6.20%</td><td>5.56%</td></tr>
<tr><td>18</td><td>12.78%</td><td>6.29%</td><td>6.49%</td><td>5.56%</td><td>6.49%</td><td>5.56%</td></tr>
</table>

Using this distribution, the minimum and maximum LFE values used in this study are –4.93% and +6.49% of the expected value, respectively.

G. 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 95ºF ambient temperatures. Winter ratings for nuclear and steam units are generally unchanged from the summer ratings. Official winter ratings for CT and CC resources can vary significantly depending upon the ambient temperature and contracted firm fuel transportation, but generally correspond to output at 40ºF ambient temperatures. 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.7 below shows the ambient temperature curves (on a per unit output basis) that were modeled within SERVM.[9]

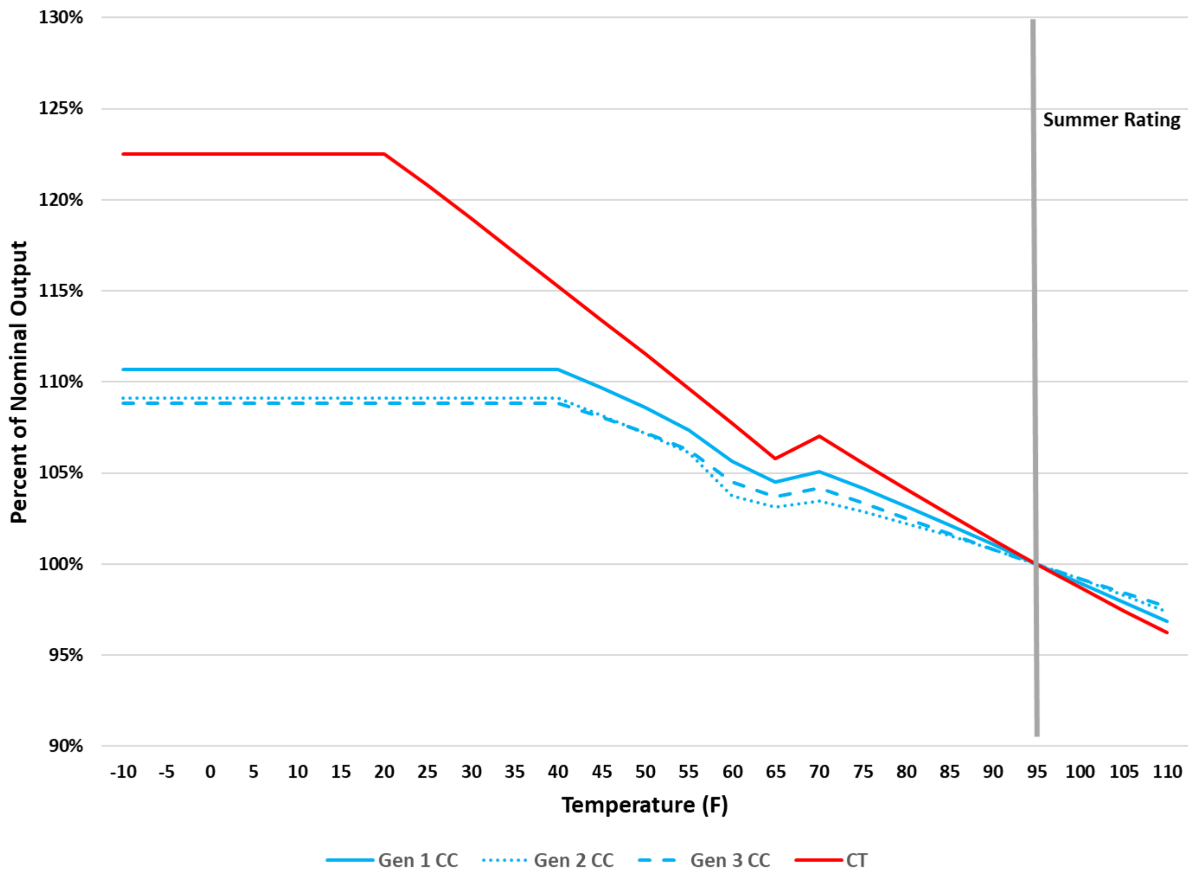

Figure I.7. Ambient Temperature Output Curves

H. 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.

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

Forced outage and maintenance outage data for the 2021 Reserve Margin Study consist of a series of observations of historical outage events from 2010-2019. 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 30,000 hours for a nuclear unit. Likewise, the typical data will contain a corresponding amount of entries in the TTR distribution, ranging from one to 700 hours. As the model processes chronologically, it will randomly choose a TTF duration from the 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-4.

Table I-4. Steam Unit Sample Time to Fail and Time to Repair Data

Unit Name	Time-to-Fail (hours)	Time-to-Repair (hours)
Sample Plant	74	77
	567	7
	970	2
	1031	4
	1604	2
	181	3
	2000	55
	322	4
	3969	20
	501	1
	6599	127

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 90% to 99%. Repair data range from 2 to 96 entries in the TTR input data records, with values ranging from an hour to nearly 25 hours.

Due to this random outage draw process, individual unit operation 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. Table I-5 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-5. Approximate EFOR by Unit Class

Unit Class	EFOR (%)
Nuclear	1.9
Coal	2.8
Gas Steam	2.0
Combined Cycle	2.1
CTs	3.3
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.8 below, confirms that the modeled outage rate is consistent with the historical outage rate and indicates that the impact of outage events is adequately modeled.

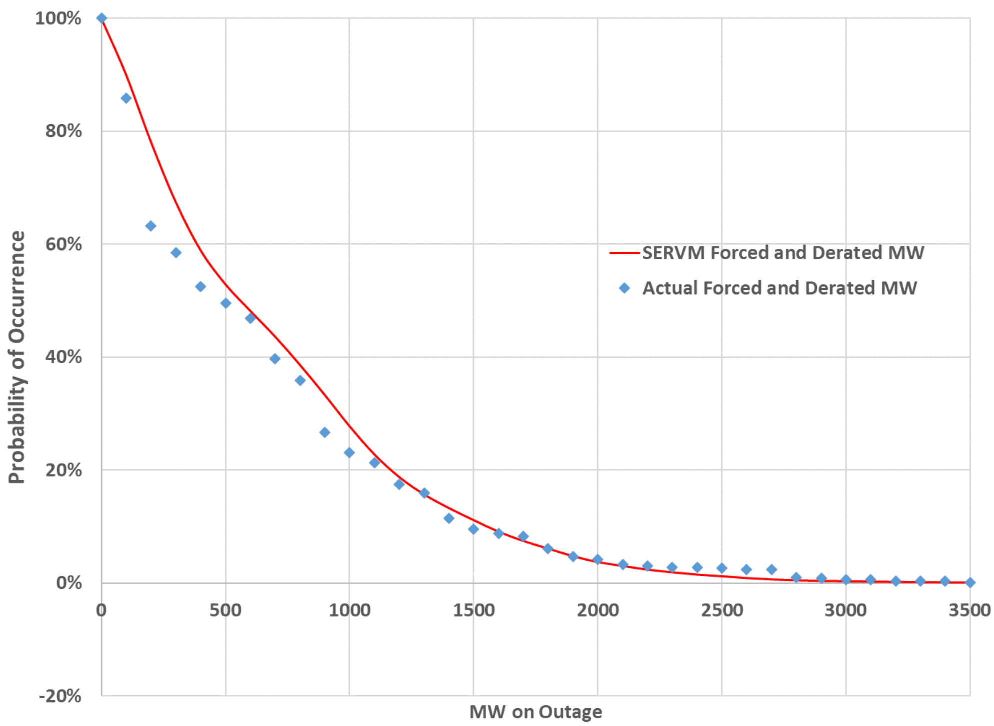

Figure I.8. Unplanned Outage Probability

I. 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, controls, or other plant equipment begins to freeze. These situations do not materialize until weather conditions are extreme, and such extreme weather conditions are less common. When they occur, though, the outage impacts can be significant and can increase in an exponential manner. Historically, these incremental outages have materialized at system weighted temperatures roughly 17°F and below. However, the Company has undertaken efforts to mitigate cold weather outages. Based on these efforts, it is expected that these incremental outages will not begin to materialize until approximately 13°F, as shown in Figure I.9 below. The figure shows (a) a trend of historical unit outages directly attributed to cold weather conditions, and (b) a trend representing the assumptions used in this study that includes expected performance improvements.

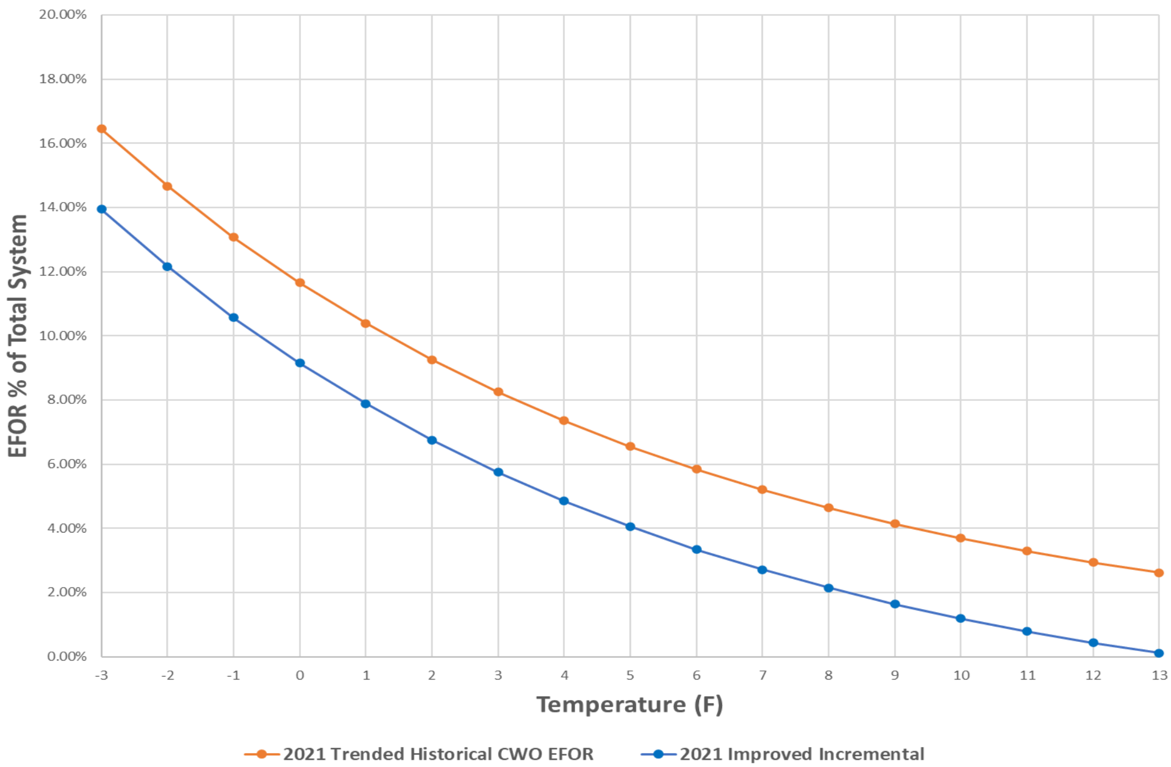

Figure I.9. Cold Weather Outage Assumptions

J. Planned and Maintenance Outage Patterns

Planned and Maintenance outages occur most often in the shoulder months because the need for units to run during the peak demand months does not allow for a lot of down time.

Traditionally, planned outage 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 the model is capable of scheduling planned outages during low load periods, it is more appropriate to model planned outages that mirror the actual outage schedules generated by the System Fleet Reliability team. This ensures that the System Planned Outage MW targets are maintained during the simulations.

Regarding maintenance outages, the model schedules these outages during low demand periods in such a way that the maintenance outage rate closely matches the desired seasonal rates, which are based on historical maintenance outage data. In general, this results in modeled maintenance outages that are reasonably consistent with the actual seasonal rates.

Figure I.10 below shows the likelihood that a resource will be assigned a planned or maintenance outage in any given month.

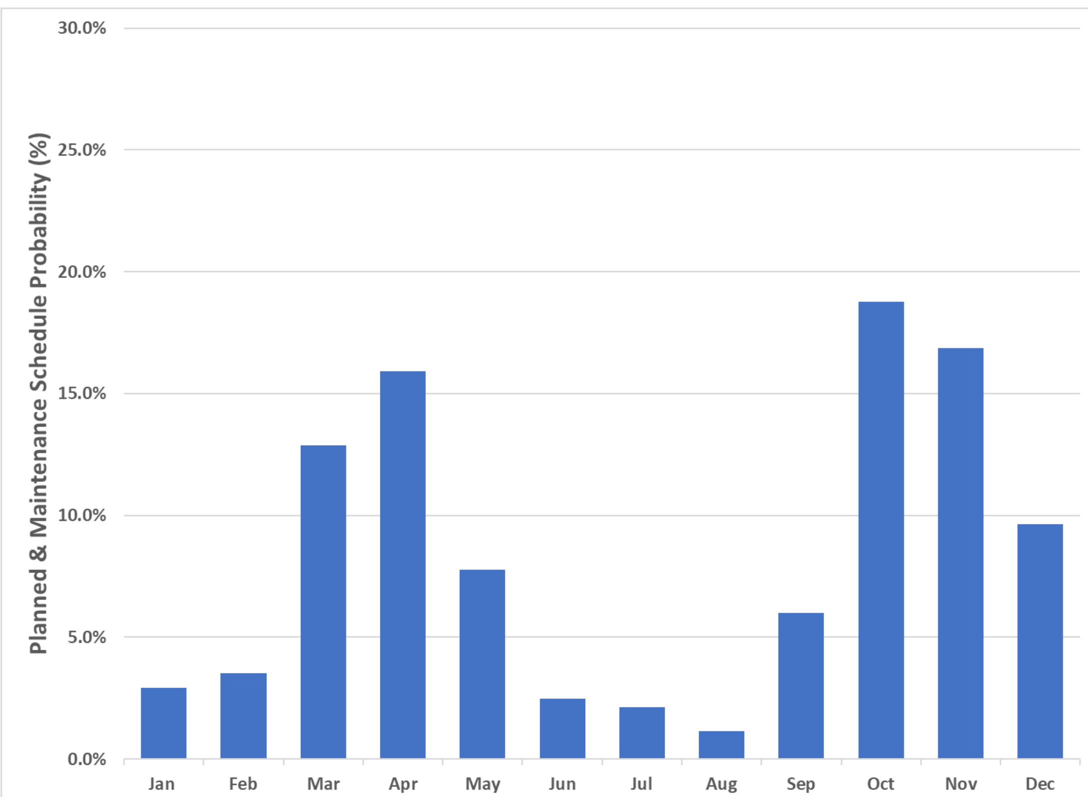

Figure I.10. Planned Outage Probability by Month

K. 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 guidance included a total operating reserve requirement of 2,182 MW, broken down according to the following components:

- Regulating Reserves: 500 MW + 8% of nominal solar capacity totaling 932 MW
- Contingency Reserve-Spinning: 625 MW
- Contingency Reserve-Supplemental (Non-Spinning): 625 MW

In addition, the Southern Balancing Authority's guidance established a firm load curtailment threshold of 1,250 MW of total operating reserves, meaning that firm load should be curtailed to maintain a minimum total operating reserve requirement of 1,250 MW. 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 318 MW of Contingency Reserve-Spinning was modeled so that the sum of Regulating Reserve and Contingency Reserve-Spinning did not exceed 1,250 MW. The remaining 932 MW of the 2,182 MW of operating reserves was modeled as Contingency Reserve-Supplemental, such that the final modeled operating reserves were as follows:

- Regulating Reserves: 932 MW
- Contingency Reserve-Spinning: 318 MW
- Contingency Reserve-Supplemental (Non-Spinning): 932 MW.

L. 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. The output of 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.11 below shows the dispatch stack order for the dispatchable resources modeled in the 2021 Reserve Margin Study. The chart excludes the energy-limited, non-dispatchable, and demand response resources.

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Figure I.11. System Dispatch Stack

M. 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 dispatchers' peak load estimate error modeled for each of these time periods was based on actual, historical forecast error data for the years 2016 through 2020. The table below shows the resulting mean and standard deviation that served as the basis for the modeled dispatchers' peak load estimate error.

Table I-6. Historical Dispatchers' 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	1.7%	5.6%	0.7%	2.5%	0.4%	1.5%
February	1.2%	2.2%	0.5%	1.8%	0.3%	1.3%
March	0.6%	1.8%	0.7%	2.1%	0.4%	1.3%
April	0.7%	3.5%	0.5%	2.7%	0.3%	1.8%
May	0.8%	5.4%	0.4%	2.2%	0.2%	1.3%
June	1.1%	4.1%	0.7%	2.3%	0.3%	1.3%
July	1.0%	4.0%	0.6%	3.2%	0.3%	1.8%
August	0.7%	2.1%	0.5%	1.6%	0.2%	0.9%
September	0.6%	4.1%	0.3%	1.7%	0.2%	1.3%
October	0.5%	3.8%	0.2%	1.9%	0.1%	1.2%
November	0.4%	9.0%	0.4%	5.6%	0.3%	5.2%
December	2.0%	15.6%	1.0%	10.4%	0.6%	8.0%

N. System-Owned Conventional Hydro Generation

System-owned hydro capacity of 2,800 MW[10] (projected for the year 2025) was divided into two components:

1) Scheduled Hydro
2) Emergency or "Unloaded" Hydro
3) Pumped Storage Hydro

This study includes 58 different hydro scenarios that are matched with the 58 weather scenarios. The 58 scenarios chosen are based on the past 58 years (1962-2019) 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.

Figure I.12 below depicts the average monthly energy produced by the two components of System-owned hydro generation. The figure illustrates the typical distribution of available hydro energy across the months of the year.

[10] Sum of average summer and winter best gate rating from installed and authorized units through 2019.

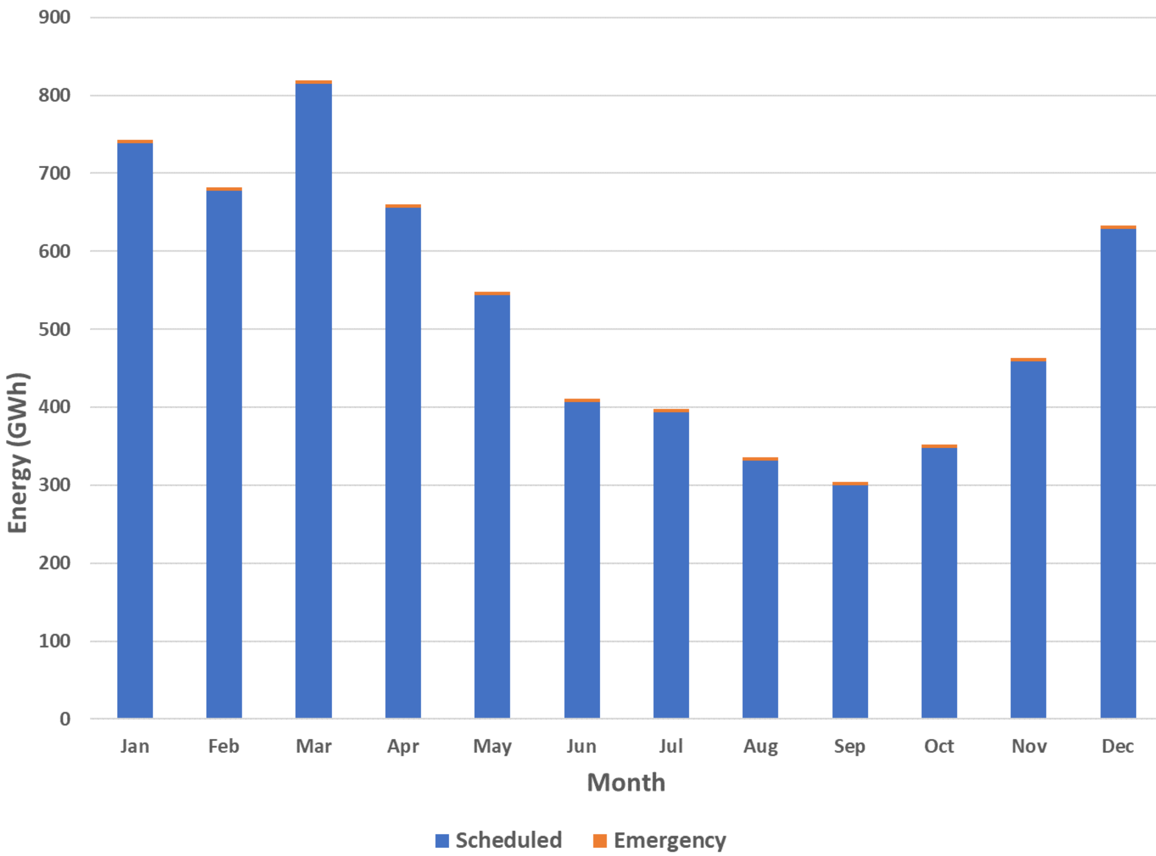

Figure I.12. Average Hydro Energy Availability

The availability of hydro energy can vary year to year for reasons largely attributed to weather. Figure I.13 below illustrates the total available scheduled hydro energies from the past 58 weather years (1962-2019).

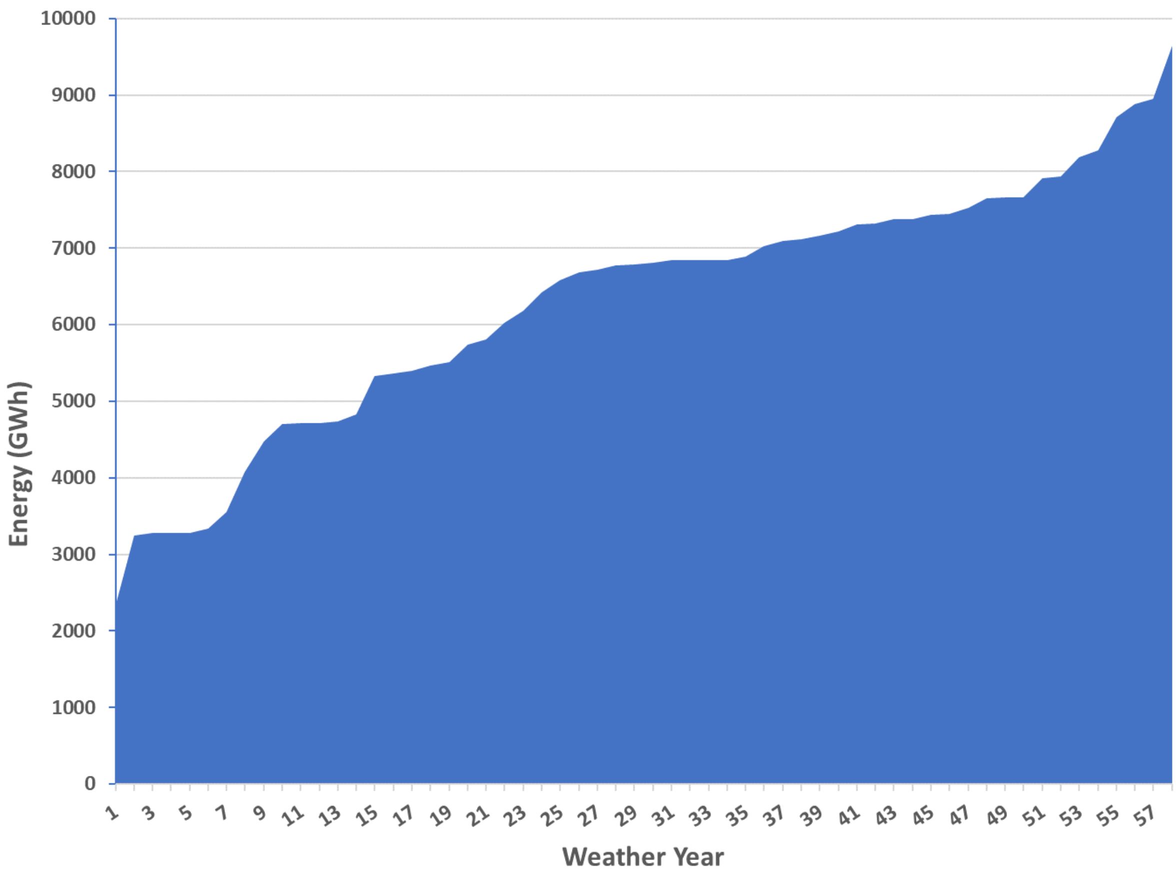

Figure I.13. Annual Scheduled Hydro Energies

O. 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 246 MW taken over four hours per weekday, with a minimum daily schedule of 612.6 MWh and a maximum monthly energy allocation of 34.381 GWh.

P. 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 585 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").

Q. Demand Response Resources

Approximately 2,986 MW of DRR capacity (contract value) is included in the analysis for the summer, and approximately 2,947 MW is 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 capacity value 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 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 with 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.

R. 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: 313 MW
- Landfill Gas: 48 MW
- Solar: 5,397 MW
- Wind: 472 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 58 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.

As solar penetration continues to grow on a yearly basis well into 2024, it is important to note that the solar impact to summer reliability remains much higher than winter. Figure I.14 below shows the expected penetration of solar resources on the system through 2024 along with their corresponding ICE summer and winter capacity values. The capacity contribution from solar resources to both seasons remains well below nominal capacity indicating that solar alone cannot meet all reliability

[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.

needs. Moreover, this capacity value continues to decrease per MW of new solar added to the System. For example, between 2022 and 2023, 1,363 MW of nominal solar capacity is expected to be added and the expected increase in summer solar capacity contributing to reliability is 294 MW or 22%. The following year an additional 1,001 MW of nominal capacity is expected but the reliability-contributing capacity is 178 MW of 17%.

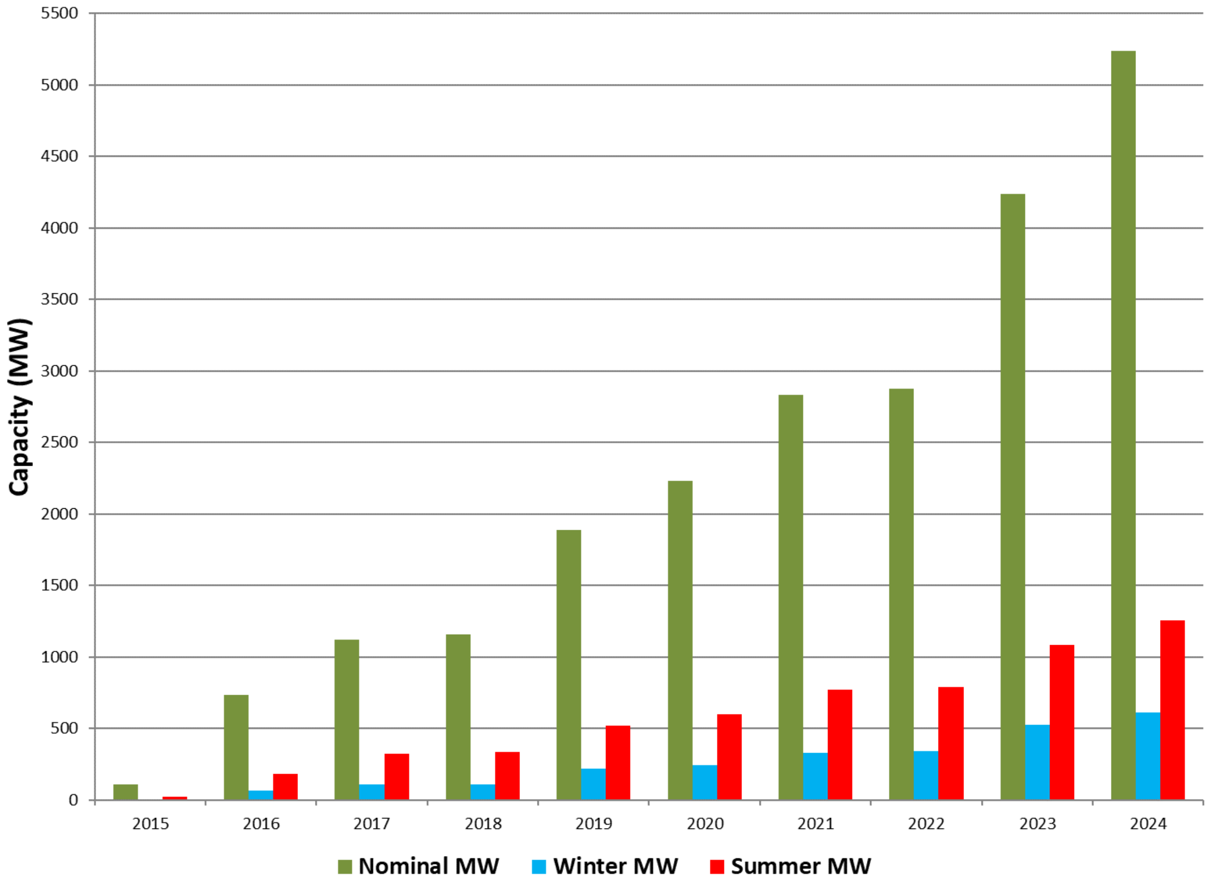

Figure I.14 Solar Resource Penetration

S. 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 most of the fleet's gas-fired units. The amounts to be procured are generally driven by the System's Fuel Policy. Although case-specific situations may allow for deviations from the Fuel Policy, for purposes of the 2021 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**. When the daily minimum temperature falls below **REDACTED**, no interruptible transportation is available for that Gas Day. Figure I.15 below illustrates the availability of interruptible transportation as modeled within SERVM.

REDACTED

Figure I.15. Interruptible Gas Transportation Availability Model

T. 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.

U. 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, as opposed to 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 2021 Reserve Margin Study, economic carrying costs based on both summer and winter performance characteristics were needed. The CT cost model is a **REDACTED REDACTED REDACTED REDACTED REDACTED** 95°F ambient temperature summer rating of 284 MW and a 40°F ambient temperature winter rating of 327 MW, 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**.

V. 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] The analysis of the survey results was updated in September 2020 by The Brattle Group. This survey was conducted among the following four customer classes:

- Residential
- Commercial (below 1 MW average demand)
- Industrial (below 1 MW average demand)
- Large business (commercial and industrial customers above 1 MW average demand)

The cost of EUE (in 2025$) for these four customer classes is shown in Table I-7 below 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.

[12] While the survey only included customers from two Operating Companies, the results are considered appropriate for all Operating Companies.

Table I-7. EUE Cost

EUE COST IN 2025$					
Outage Scenario	**Residential ($/kWh)**	**Commercial ($/kWh)**	**Industrial ($/kWh)**	**Large Business ($/kWh)**	**Weighted Average ($/kWh)**
Weighting Factor (%)	26.40%	19.29%	1.73%	52.58%	
1 hour, no warning, summer	$2.45	$165.74	$121.44	$33.95	$52.57
Contribution to Weighted Average	$0.65	$31.98	$2.10	$17.85	
1 hour, no warning, winter	$2.23	$105.19	$82.03	$25.16	$35.53
Contribution to Weighted Average	$0.59	$20.30	$1.42	$13.23	

The result was a Value of Loss Load ("VOLL") of $52.57/kWh for summer and $35.53/kWh for winter.

II. SIMULATION PROCEDURE

A. Case Specification

The simulations performed for the 2021 Reserve Margin Study were designed to estimate System generation reliability across a wide range of weather conditions, LFEs, and reserve margins. Thirteen discrete reserve margin levels were simulated to calculate the expected costs over a broad range of scenarios. Load shapes corresponding to the 116 weather datasets (58 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 below.

Table II-1. SERVM Case Variables

Weather and Hydro Years	Winter Reserve Margins	LFEs
1962-2019	20%	6.49%
	21%	4.31%
	22%	0.00%
	23%	-2.44%
	24%	-4.93%
	25%	
	26%	
	27%	
	28%	
	29%	
	30%	
	31%	
	32%	

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 58 × 2 × 13, or 1,508 cases. Considering the five load forecast points yields 7,540 cases (58 × 2 × 13 × 5 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 754,000 production cost simulations (58 x 2 x 13 x 5 x 100 cases). Estimating EUE for each of the 754,000 simulations provides sufficient data for regression analysis of other combinations not specifically simulated. This set of simulations was performed for both 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 58 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 116 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 five forecast errors has its own probability of occurrence. For each reserve margin studied, the combined set of input variables results in 580 individual cases having their own designated probability of occurrence to be used in the probabilistic evaluation. Table II-2 below depicts the probabilities assigned to each of these variables and the resulting probability for each case. This total case probability is determined by multiplying 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 (1 in 58)	Start Days Probability (1 in 2)	Total Case Probability
-4.93%	0.056	0.017241379	0.5	0.000483
-2.44%	0.222	0.017241379	0.5	0.001914
0.00%	0.444	0.017241379	0.5	0.003828
4.31%	0.222	0.017241379	0.5	0.001914
6.49%	0.056	0.017241379	0.5	0.000483

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.

For each of the 580 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 to establish "Reliability Cost." Figure II.1 below shows the formula used for calculating EUE. Other components are calculated similarly.

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

where

$$\boldsymbol{Y = EUE\ and,}$$

$$\boldsymbol{n = number\ of\ cases}$$

Figure II.1 Variable Calculation Formula

Table II-3 thru Table II-6 below 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 26% winter reserve margin simulation.

Table II-3. Sample Calculation Top 10 Worst Reliability Costs at 26% Winter 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	13,035	35,528	13,615	REDACTED	758	REDACTED
2	REDACTED	REDACTED	10,658	35,528	13,192	REDACTED	1,006	REDACTED
3	REDACTED	REDACTED	16,490	35,528	16,389	REDACTED	1,164	REDACTED
4	REDACTED	REDACTED	16,064	35,528	16,870	REDACTED	616	REDACTED
5	REDACTED	REDACTED	4,291	35,528	14,962	REDACTED	2,400	REDACTED
6	REDACTED	REDACTED	3,905	35,528	15,751	REDACTED	2,179	REDACTED
7	REDACTED	REDACTED	7,097	35,528	24,860	REDACTED	2,311	REDACTED
8	REDACTED	REDACTED	6,917	35,528	23,195	REDACTED	1,812	REDACTED
9	REDACTED	REDACTED	6,111	35,528	10,077	REDACTED	712	REDACTED
10	REDACTED	REDACTED	21,054	35,528	21,970	REDACTED	915	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	0.003827	REDACTED	463.11	REDACTED	REDACTED	REDACTED	REDACTED
2	0.003827	REDACTED	378.66	REDACTED	REDACTED	REDACTED	REDACTED
3	0.001914	REDACTED	585.87	REDACTED	REDACTED	REDACTED	REDACTED
4	0.001914	REDACTED	570.71	REDACTED	REDACTED	REDACTED	REDACTED
5	0.003827	REDACTED	152.45	REDACTED	REDACTED	REDACTED	REDACTED
6	0.003827	REDACTED	138.75	REDACTED	REDACTED	REDACTED	REDACTED
7	0.001914	REDACTED	252.14	REDACTED	REDACTED	REDACTED	REDACTED
8	0.001914	REDACTED	245.76	REDACTED	REDACTED	REDACTED	REDACTED
9	0.001914	REDACTED	217.11	REDACTED	REDACTED	REDACTED	REDACTED
10	0.000483	REDACTED	748.01	REDACTED	REDACTED	REDACTED	REDACTED

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

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	0.003827	REDACTED	REDACTED	4,180.28	16.00
2	0.003827	REDACTED	REDACTED	4,145.30	15.86
3	0.001914	REDACTED	REDACTED	4,470.39	8.56
4	0.001914	REDACTED	REDACTED	4,415.08	8.45
5	0.003827	REDACTED	REDACTED	4,215.22	16.13
6	0.003827	REDACTED	REDACTED	4,215.63	16.13
7	0.001914	REDACTED	REDACTED	4,449.68	8.52
8	0.001914	REDACTED	REDACTED	4,462.64	8.54
9	0.001914	REDACTED	REDACTED	3,792.97	7.26
10	0.000483	REDACTED	REDACTED	4,832.63	2.33

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.

III. BASE CASE RESULTS

A. Winter 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), which 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 24.25%, represents the EORM. This graph is presented below.

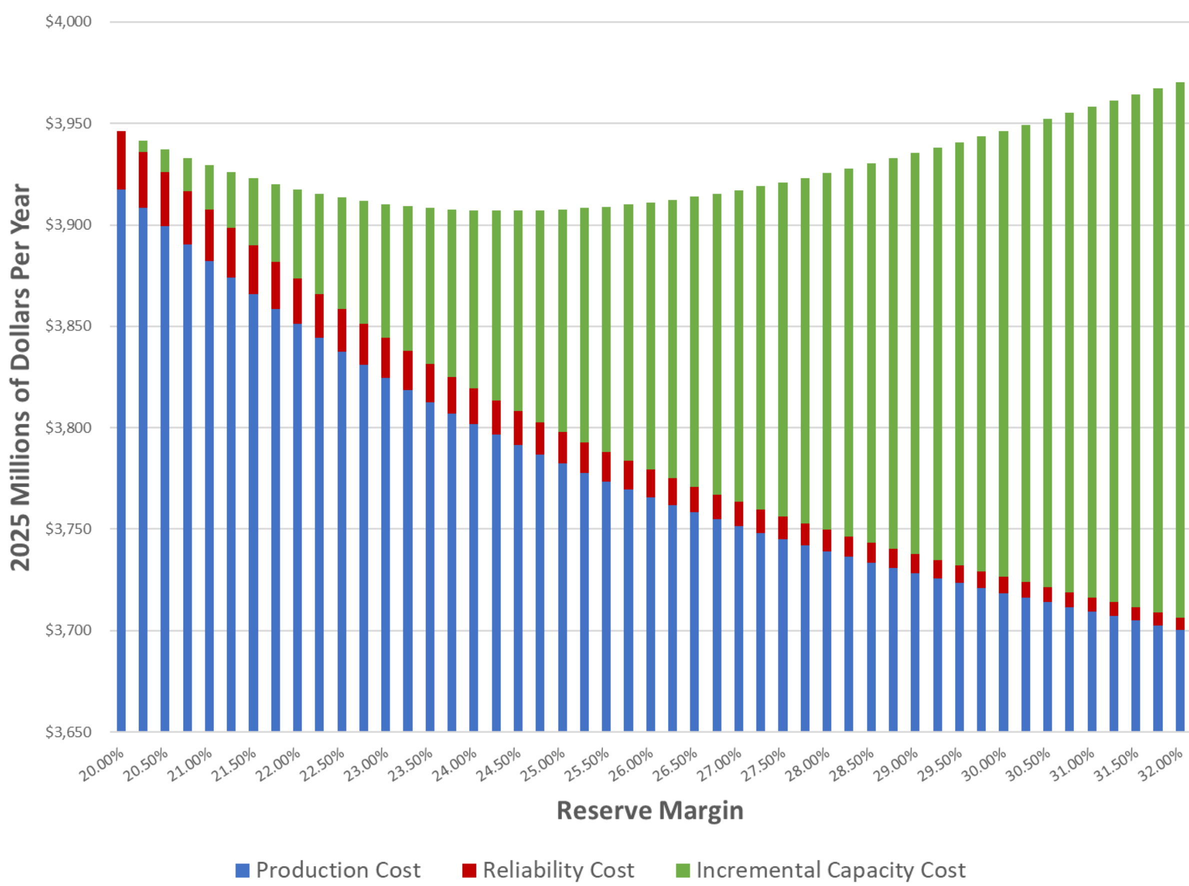

Figure III.1. Winter EORM U-Curve

Currently, the six key determinants affecting winter reliability risk include:

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
e. increased reliance on natural gas
f. the availability of market purchases

Because all these drivers will impact winter reliability, the System's primary reliability risk continues to be in the winter. To further demonstrate that winter reliability risk exceeds that of the summer, an additional study was performed with reserve margin levels ranging from 10-20% that had several winter drivers removed, including no fuel constraints and no cold weather outages. The reserve margin range was reduced from the 20-32% performed in the winter study due to the low summer EUE in that reserve margin range. The seasonal EUE data from this study is shown in Figure III.2 below. Through all reserve margin levels, EUE is greater in the winter than in the summer.

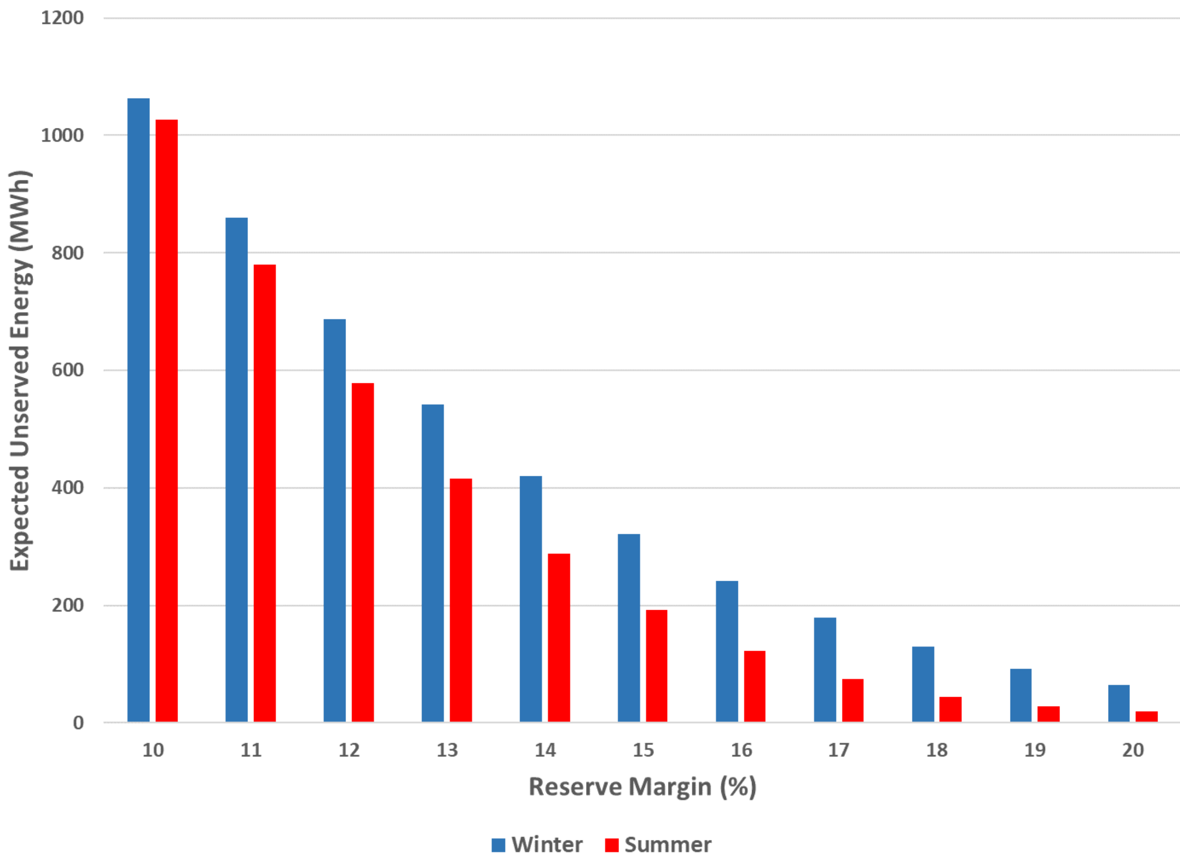

Figure III.2. Seasonal EUE by Reserve Margin

B. Summer-Only Reserve Margin Results

Given that the System's primary reliability risk is in the winter, it is possible to determine a summer-only reserve margin without consideration of any winter economics or reliability risks. The following graph shows that the Summer-Only EORM, without consideration of winter months and related winter drivers, would be 20.50%.

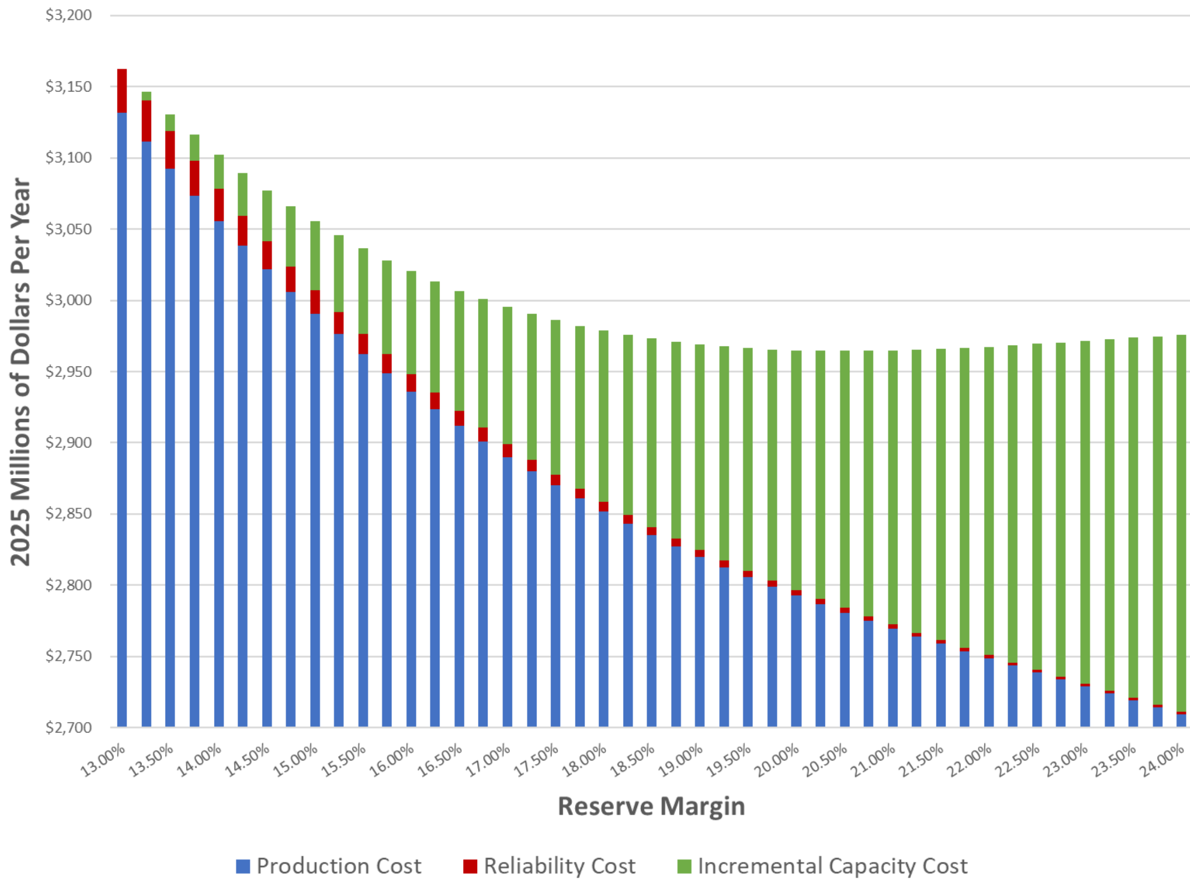

Figure III.3. Summer-only EORM U-Curve (Without Winter Months)

There are several factors that contribute to the summer-only EORM being lower than winter. The primary drivers related to cold-weather outages and the availability of interruptible natural gas fuel do not apply to the summer-only run because summer temperatures do not drop low enough for those variables to affect summer reliability. However, other drivers differentiating the seasons remain. Those include higher winter volatility and more market resources being available in the summer, leading to more economic market purchases. This is caused by many of Southern Company's northern neighbors being modeled as carrying more summer reserves once they were calibrated to an annual reliability level of 1-in-10, as shown in Table I-1 and Table I-2. Figure III.4 below shows the average monthly purchases by season excluding the cold weather outage and fuel availability winter drivers.

REDACTED

Figure III.4. Average Monthly Energy Purchases by Reserve Margin

C. Risk Analysis

The winter-focused combination of Production Cost, Reliability Cost, and Incremental Capacity Cost results in a EORM of 24.25%. 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 below illustrates the volatility in Production Cost and Reliability Cost exposure. In scenarios in which load grows faster than expected, temperatures are higher (or lower) than expected, or unit performance is poorer than expected, the cost exposure can be much higher than the expected case.

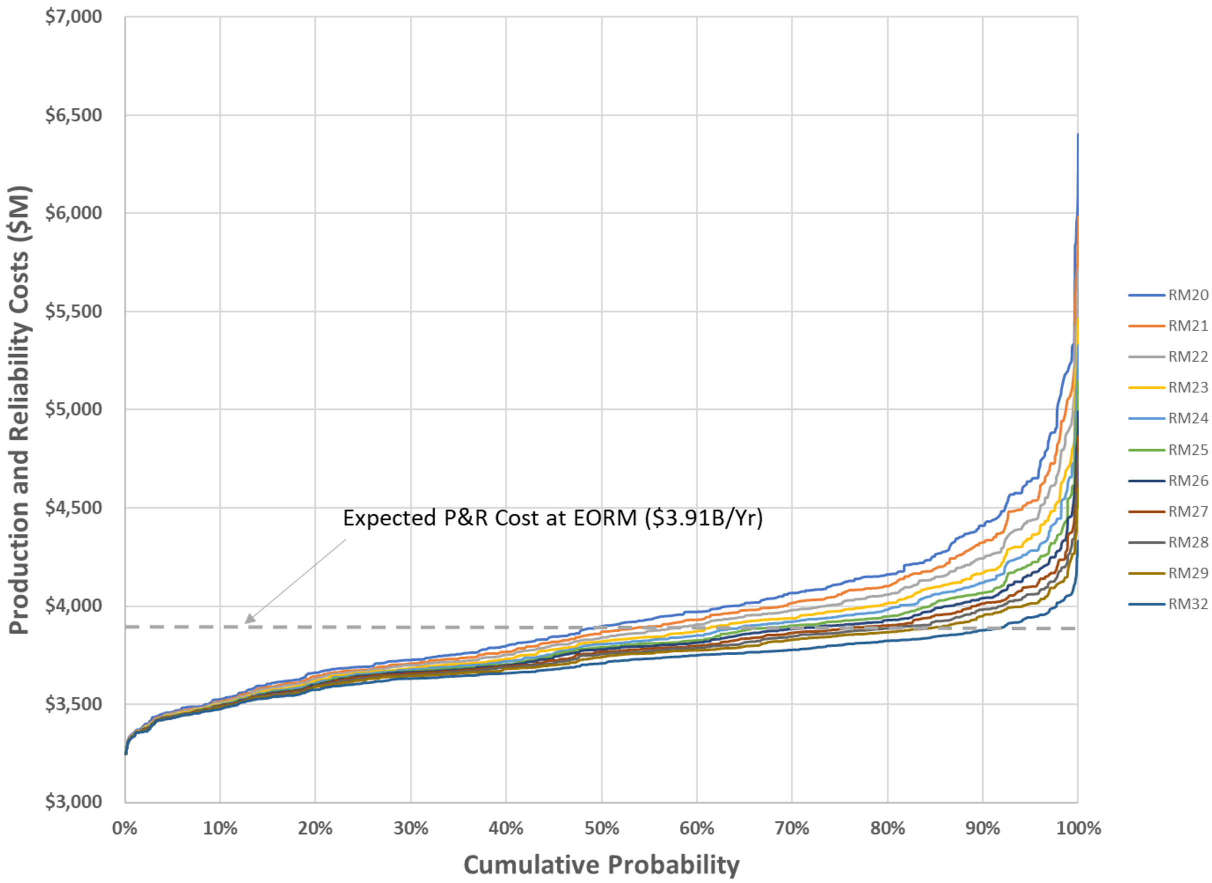

Figure III.5. Production and Reliability Cost Distributions for Winter Reserve Margins

Focusing 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 below 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 20% winter reserve margin shows over $6 billion per year in total exposure, while the most extreme case at a 26% reserve margin is approximately $4.9 billion.

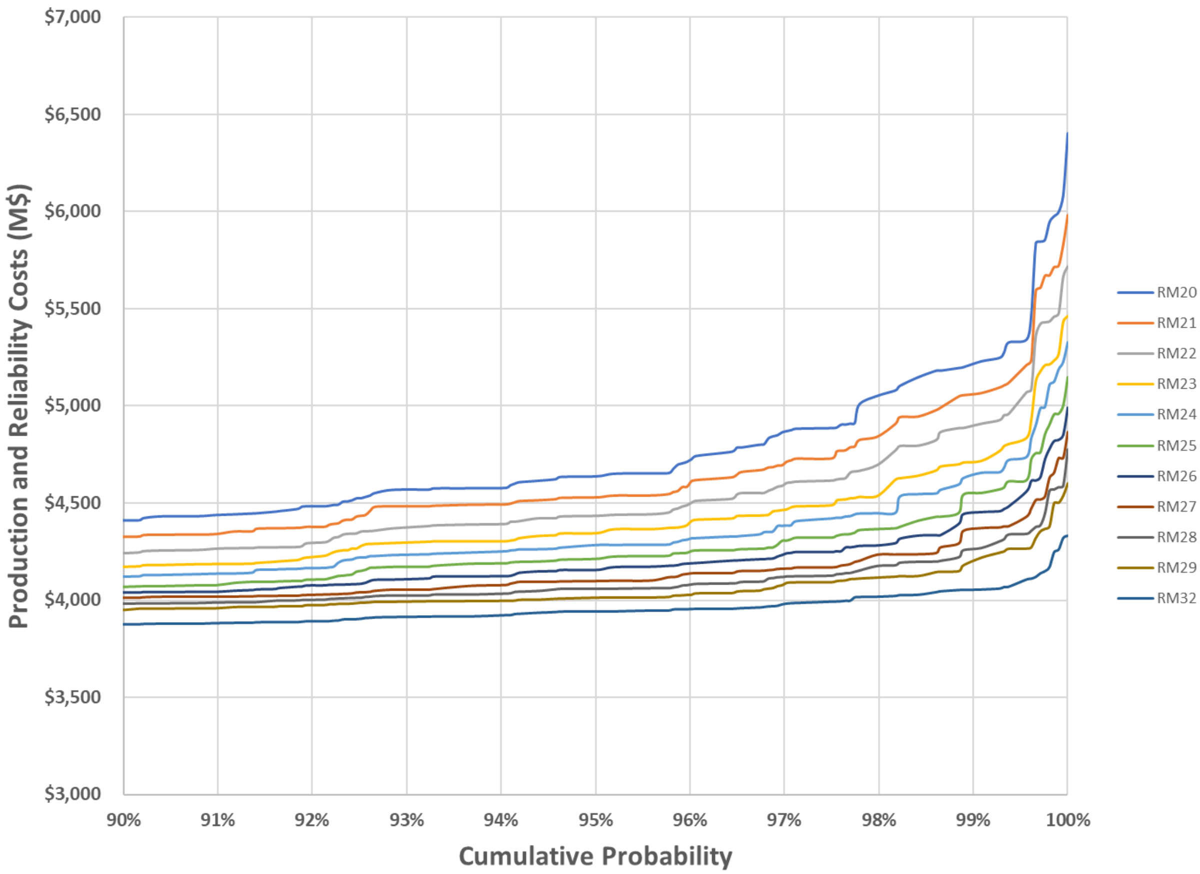

Figure III.6. Top 10% Distribution for Winter Reserve Margins

To protect against the potential for an extremely high-cost outcome, additional risk analyses should be performed to compare highly volatile Production Costs and Reliability Costs and fixed Incremental Capacity Cost. 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 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. To evaluate the risk of these potential high-cost outcomes and thus determine how much of an “insurance premium” to pay, a risk metric called Value at Risk (“VaR”) is used.

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 increase 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 reasonable 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$)
20.00%	3,946.2	224.2	321.2	480.8	749.1
20.25%	3,941.5	218.8	314.6	466.5	727.8
20.50%	3,937.1	213.7	308.3	452.7	707.2
20.75%	3,933.1	208.9	302.3	439.6	687.2
21.00%	3,929.3	204.4	296.7	426.9	667.9
21.25%	9,325.9	200.0	291.3	414.9	649.3
21.50%	3,922.8	196.0	286.2	403.3	631.2
21.75%	3,920.0	192.1	281.4	392.2	613.8
22.00%	3,917.5	188.5	276.7	381.6	596.9
22.25%	3,915.3	185.1	272.2	371.4	580.5
22.50%	3,913.4	181.8	267.8	361.8	564.7
22.75%	3,911.7	178.8	263.6	352.5	549.4
23.00%	3,910.3	176.0	259.5	343.7	534.6
23.25%	3,909.2	173.3	255.4	335.3	520.3
23.50%	3,908.3	170.8	251.4	327.3	506.4
23.75%	3,907.6	168.4	247.4	319.6	493.0
24.00%	3,907.2	166.2	243.5	312.3	480.0
24.25%	3,907.0	164.2	239.6	305.4	467.5
24.50%	3,907.0	162.3	235.7	298.8	455.3
24.75%	3,907.2	160.5	231.9	292.5	443.6
25.00%	3,907.6	158.8	228.0	286.5	432.2

25.25%	3,908.2	157.2	224.1	280.8	421.2
25.50%	3,909.0	155.7	220.2	275.4	410.6
25.75%	3,910.0	154.3	216.3	270.2	400.4
26.00%	3,911.1	153.0	212.4	265.3	390.4
26.25%	3,912.4	151.8	208.5	260.6	380.9
26.50%	3,913.8	150.6	204.6	256.2	371.6
26.75%	3,915.5	149.5	200.7	251.9	362.7
27.00%	3,917.2	148.5	196.9	247.9	354.1
27.25%	3,919.1	147.5	193.0	244.0	345.8
27.50%	3,921.1	146.6	189.2	240.2	337.8
27.75%	3,923.2	145.7	185.5	236.6	330.2
28.00%	3,925.4	144.8	181.8	233.2	322.8
28.25%	3,927.8	144.0	178.2	229.9	315.7
28.50%	3,930.2	143.1	174.7	226.6	308.9
28.75%	3,932.7	142.3	171.4	223.5	302.4
29.00%	3,935.3	141.5	168.2	220.4	296.3
29.25%	3,938.0	140.7	165.3	217.4	290.4
29.50%	3,940.7	139.9	162.5	214.5	284.8
29.75%	3,943.5	139.0	159.9	211.6	279.5
30.00%	3,946.3	138.2	157.7	208.7	274.5
30.25%	3,949.2	137.3	155.7	205.8	269.8
30.50%	3,952.2	136.5	154.1	203.0	265.4
30.75%	3,955.1	135.5	152.8	200.1	261.3
31.00%	3,958.1	134.6	152.0	197.2	257.5
31.25%	3,961.1	133.6	151.6	194.2	254.0
31.50%	3,964.1	132.5	151.8	191.2	250.9
31.75%	3,967.1	131.5	152.5	188.1	248.1
32.00%	3,970.1	130.3	153.7	185.0	245.6

For the 85th percentile of risk (VaR85), the incremental increase in expected cost roughly equals the incremental decrease in VaR85 when moving from 29.25% reserve margin to 29.50% reserve margin. At this point, the incremental increase in cost is $3,940.7M - $3,938.0M = $2.7M; and the decrease in VaR85, or decrease in customers' exposure to higher cost outcomes, is $162.5M - $165.3M = -$2.8M. Moving from 29.50% to 29.75% results in an increase in expected costs ($3,943.5M – $3,940.7M = $2.8M) that is greater than the decrease in VaR85 ($159.9M – $162.5M = $-2.6M). Thus, 29.50% represents the EORM at the 85th percentile of risk. Compared to the expected case TRM of 24.25%, a 29.50% reserve margin reduces the VaR85 exposure by $77.1M/year, while increasing the expected case cost by $33.7M/year. Lower and higher confidence intervals were also examined. At the 80th percentile of risk, it would be justifiable to establish a reserve margin of 26.00%. At the 90th percentile of risk, it would be justifiable to establish a reserve margin of 30.00%. Likewise, at the 95th percentile of risk, it would be justifiable to establish a reserve margin of 31.50%. However, the increased expected costs for these three confidence intervals are $4.1M/year, $39.3M/year and $57.1M/year, respectively. While justifiable from a cost/risk reduction perspective, the absolute increase in expected cost of a reserve margin at the 90th or 95th confidence interval, or even at the EORM of the 85th confidence interval, suggests use of the current Target Reserve Margin of 26%, which happens to coincide with the 80th confidence interval as it did in the 2018 Reserve Margin Study, remains appropriate.

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 85th percentile of cost. This is precisely what the Var85 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 the 85th confidence interval. The resulting "U-Curve" confirms that the EORM at the 85th confidence interval is 29.5% - that is, 29.5% is the risk-adjusted EORM at the 85th confidence interval.

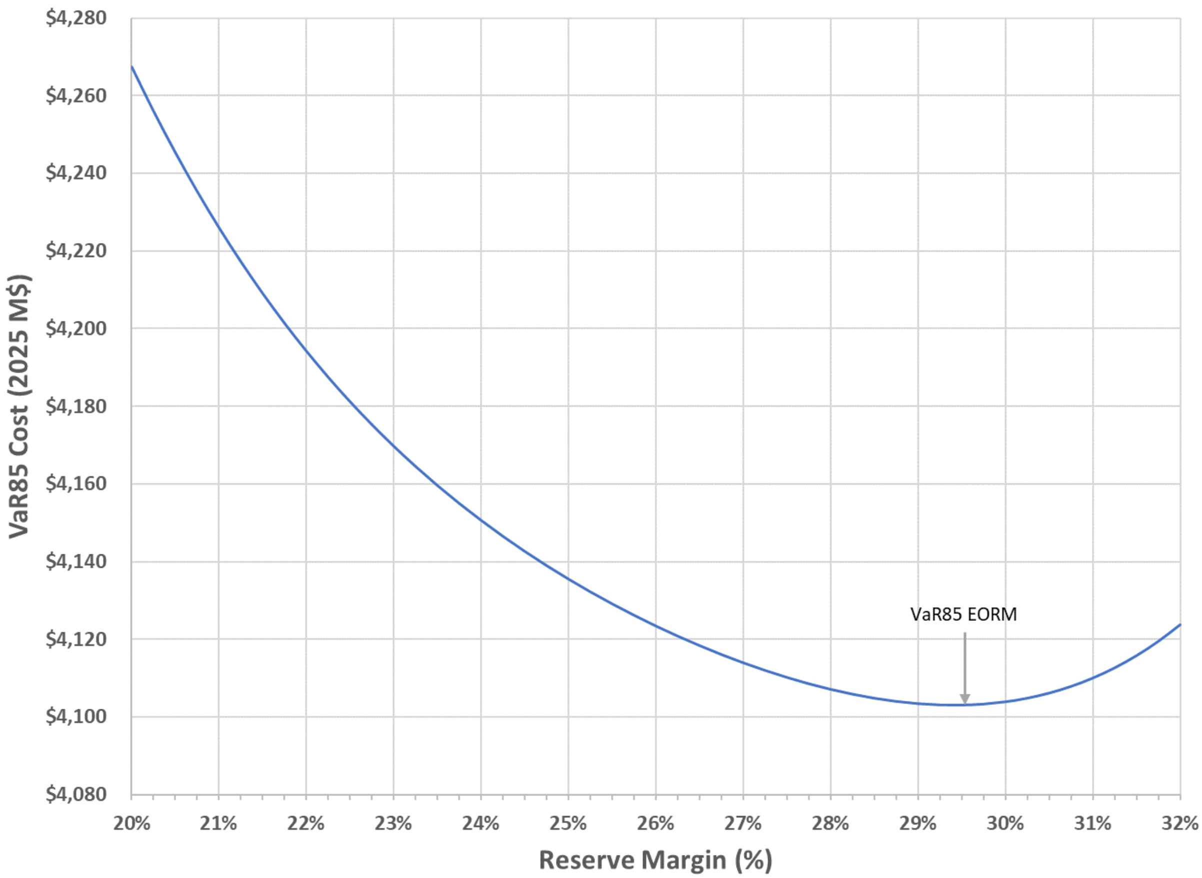

Figure III.7 85% Confidence Interval U-Curve

D. Loss of Load Expectation

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 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.

For the Southern Company System, this 1:10 LOLE threshold occurs at reserve margins below the EORM. Thus, the primary focus has historically been on the risk-adjusted EORM to establish the TRM.

Figure III.8 below illustrates how this metric looks for the System over the range of reserve margins studied for the 2021 Reserve Margin Study as compared to the 2018 Reserve Margin Study.

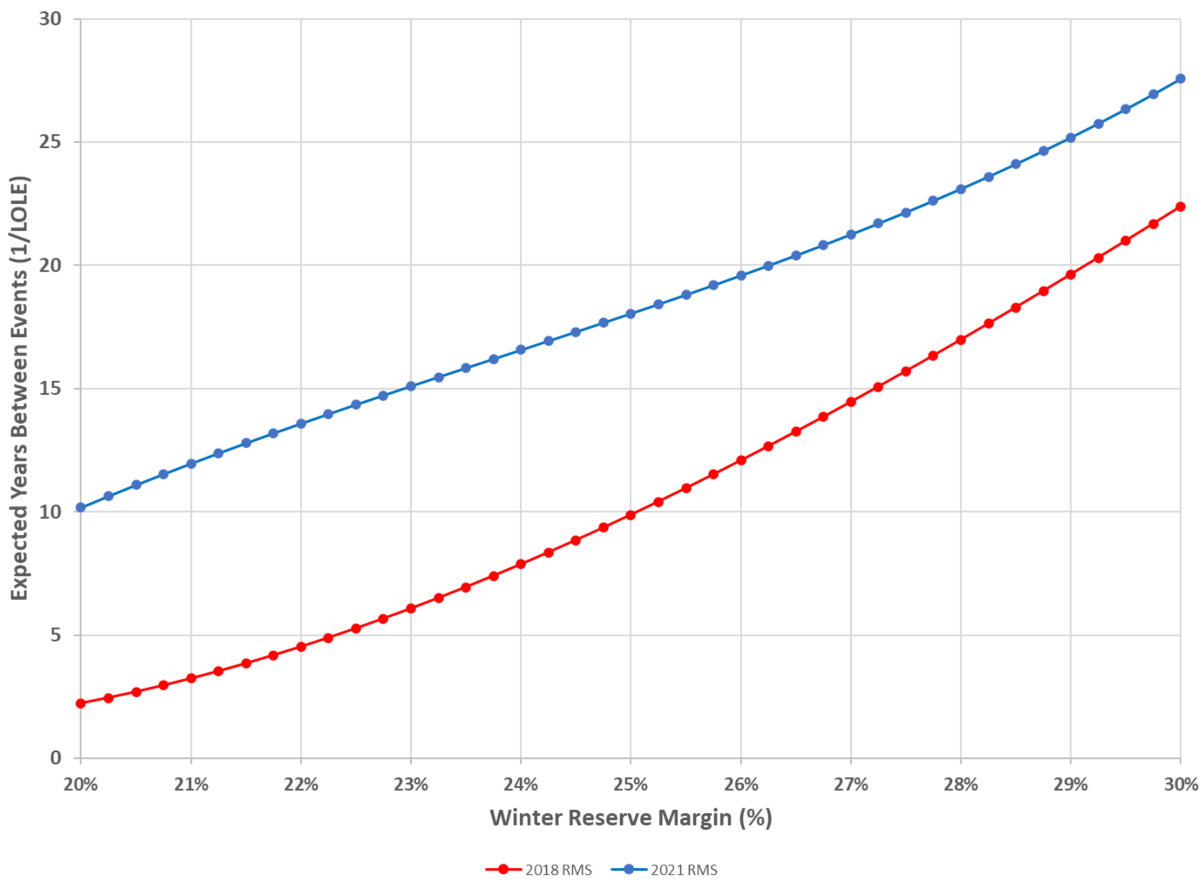

Figure III.8 LOLE for Winter Reserve Margins

At the winter EORM of 24.25%, the LOLE is 0.059 days per year or an expectation of one event every 16.9 years. To achieve a 1:10 LOLE threshold would require a winter reserve margin of 20.00% which is below the EORM and VaR85 reserve margins. Accordingly, the 1:10 LOLE threshold represents the absolute minimum level of the desired reserve margin range for both winter and summer, but it is not the most economic or risk adjusted Reserve Margin level for customers.

E. 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
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 capacity by its economic carrying cost. For the 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 333.5 MW or **REDACTED REDACTED** in carrying cost. For the winter focus study, the cost was determined using winter performance values, resulting in a carrying cost of **REDACTED REDACTED**. To achieve an increase of one percent reserve margin in the winter focus study requires the addition of 327.10 MW 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.9 below (for the winter focus study), which shows a linear increase in costs when graphed as a function of reserve margin.

REDACTED

Figure III.9. 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.10 below illustrates Reliability Cost as a function of winter reserve margin.

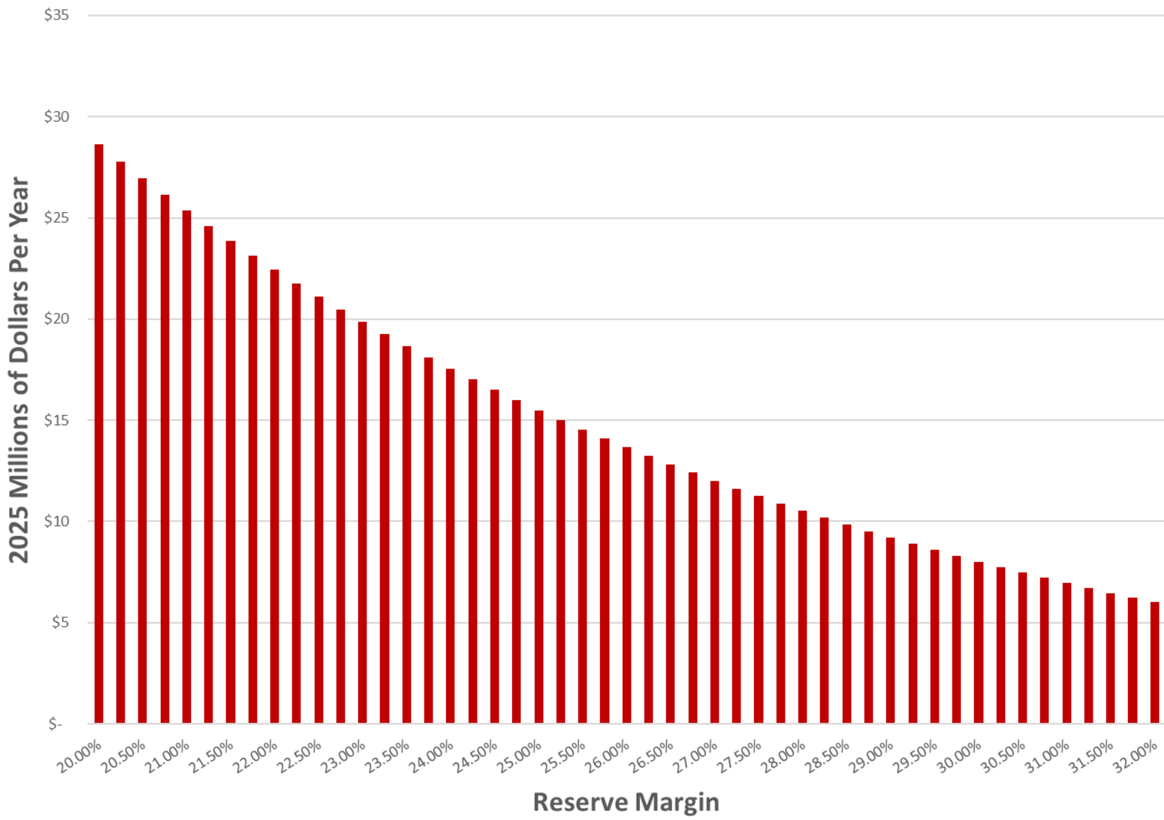

Figure III.10. Reliability Cost

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.11 below.

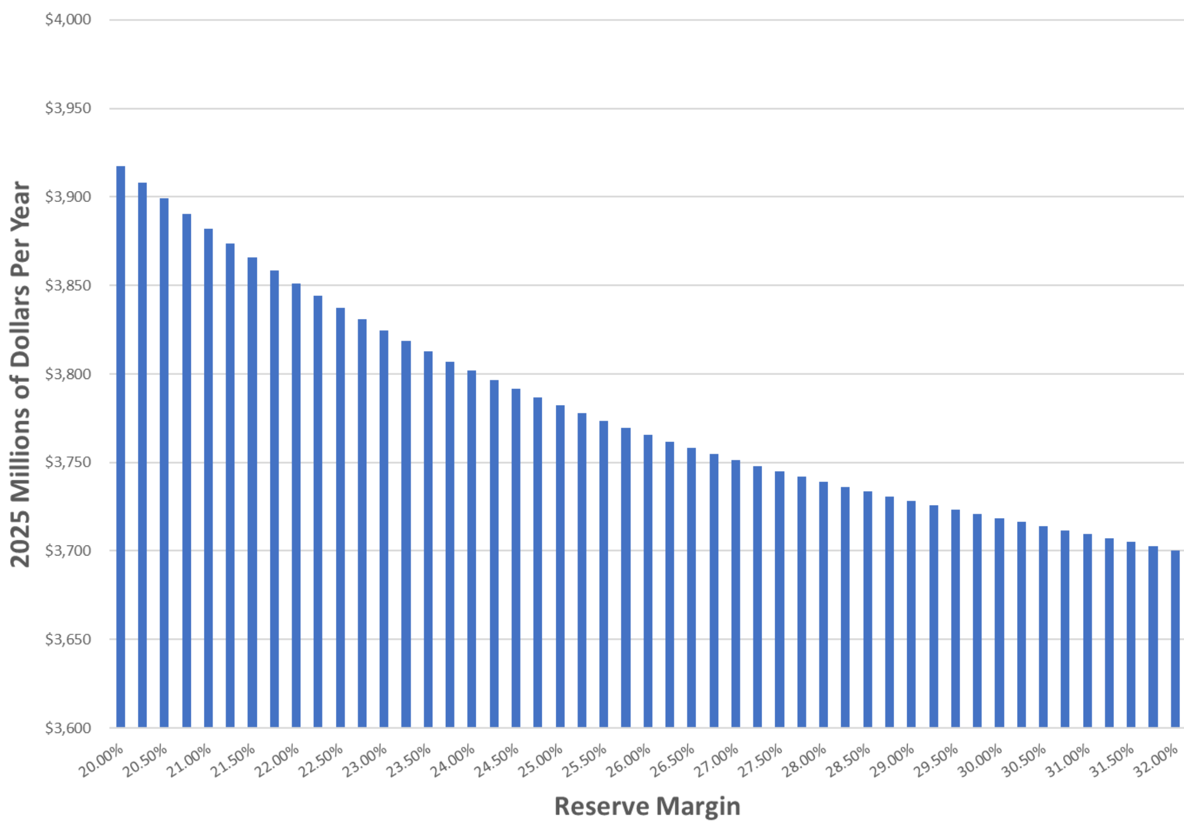

Figure III.11. Production Cost

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

F. Components of the Winter Target Reserve Margin

To fully understand the relative contribution of the components of the overall EORM, several individual sensitivities were run for each of the following components of uncertainty: weather, market risk, unit performance, load forecast error, and fuel supply. Additionally, a broader sensitivity was run that excluded all components of uncertainty. This all-encompassing sensitivity represents a base level of reserve margin due solely to economics, or Generation Economics. A risk adjustment representing the delta between the EORM and risk adjusted EORM was also calculated. Figure III.12 below shows the contribution of all components toward the overall required Winter TRM of 26%.

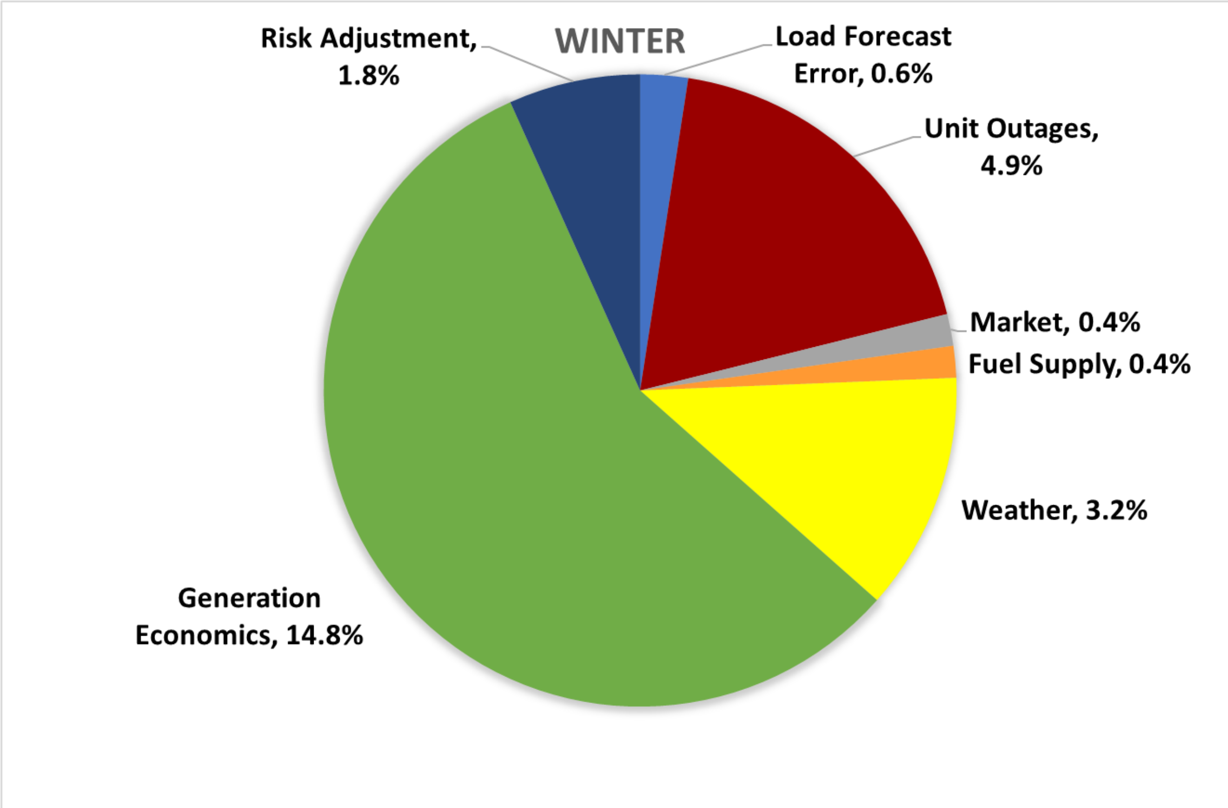

Figure III.12 Economic Components of Winter TRM

IV. SENSITIVITY ANALYSES

The data for unit performance, weather, load forecast error, hydro availability, market prices, and other inputs is based on 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 minimum 1:10 LOLE threshold.

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 2021 Reserve Margin Study represents the economic carrying cost of a CT. The capacity price sensitivity examined a range of capacity costs from values significantly above and below the economic carrying cost of a dual fuel CT. Figure IV.1 below shows how capacity costs across these ranges affect the Winter EORM. For example, at **REDACTED REDACTED**, the Winter EORM moved from 24.25% to almost 28%. Capacity price does not impact the 1:10 LOLE threshold.

REDACTED

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

Two cost-of-EUE sensitives were evaluated.

B. Minimal Cost of EUE

The first cost of EUE sensitivity was a minimum value assuming only impacts from residential class customers. This resulted in a cost of EUE of approximately $2,400/MWh of outage (in 2025$). The Winter EORM for this sensitivity moved from 24.25% to 23.75%. There was no change in the 1:10 LOLE threshold.

C. Publicly Available Cost of EUE

The second cost of EUE sensitivity was developed based on publicly available cost of EUE data. Using the Interruption Cost Estimate Calculator (developed by Nexant, funded by Lawrence Berkeley

National Laboratory and the Department of Energy, and publicly available at http://icecalculator.com), a cost of EUE for the System was estimated to be approximately $44,000/MWh (2025$). The Winter EORM for this sensitivity moved from 24.25% to 24.50%. There was no change in the 1:10 LOLE threshold.

D. No Cold Weather Outages

As indicated in Section I, the cold weather outage assumptions used in the 2021 Reserve Margin Study incorporated additional, temperature-related unit outages below 13°F. This sensitivity assumes that there are no additional outages at extremely low temperatures. The Winter EORM for this sensitivity moved from 24.25% to 24.00%. The 1:10 LOLE threshold moved from 20.00% to 17.50%.

E. 50% Reduced Transmission

For this sensitivity, transmission capabilities with neighboring regions were reduced by 50%. The Winter EORM for this sensitivity did not change from the base case. The 1:10 LOLE threshold moved from 20.00% to 20.50%,

F. 50% Increased Transmission

For this sensitivity, transmission capability with neighboring regions and between neighboring regions was increased by 50%. This 50% increased transmission scenario resulted in a decrease in the Winter EORM from 24.25% to 23.75%. It also resulted in a decrease in the 1:10 LOLE threshold from 20.00% to 19.50%.

G. 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 24.25% to 25.00%. Similarly, the 1:10 LOLE threshold increased from 20.00% to 21.25%.

H. 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 24.25% to 23.25%. Similarly, the 1:10 LOLE threshold decreased from 20.00% to 18.50%.

Summary of Sensitivity Analysis

Figure IV.2 below graphs the results of all the sensitivity analyses (*i.e.*, Sensitivities A through H). For Sensitivity A (capacity costs), two results are shown, representing capacity prices associated with half of the economic carrying cost of a CT (A) and 1.5 times 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 2021 Reserve Margin Study and indicate that its results are robust against those sensitivities. Table IV.1 below presents the same sensitivity data.

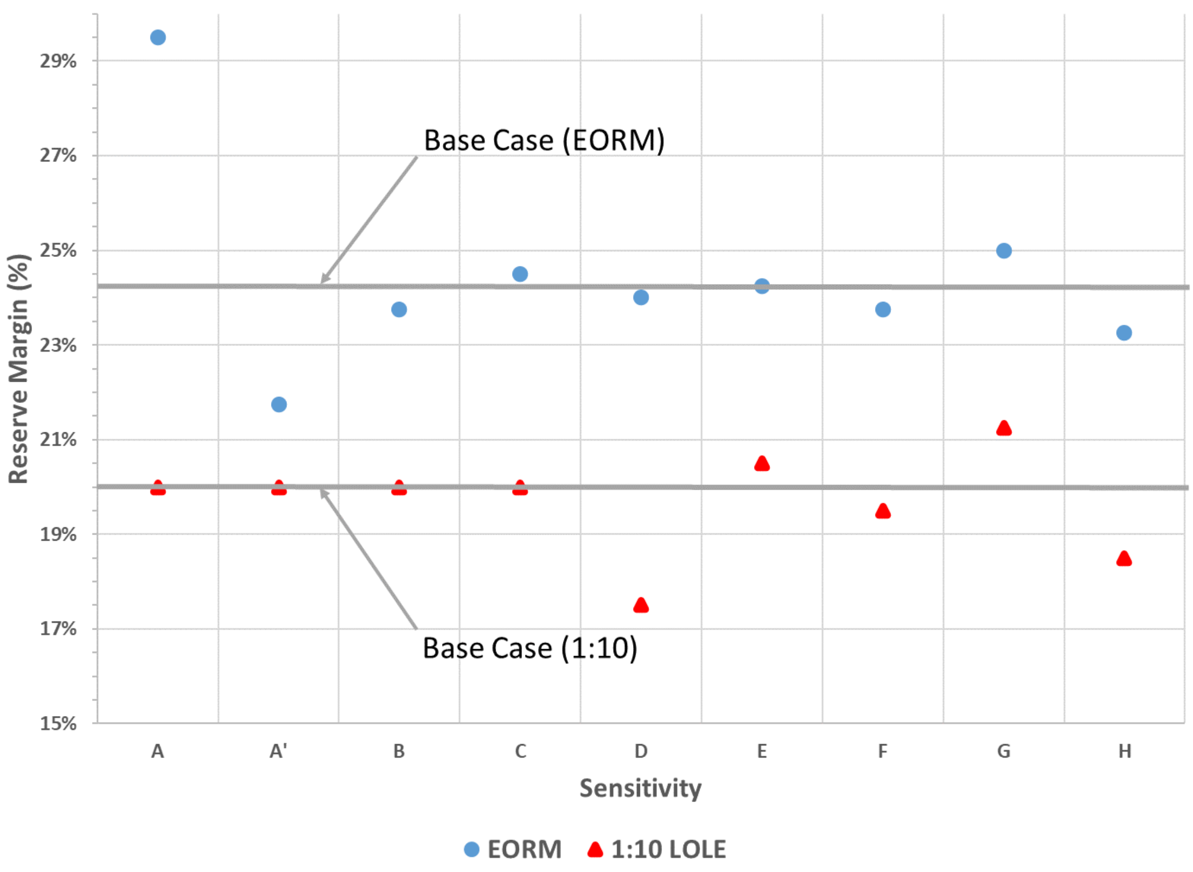

Figure IV.2. Winter Sensitivity Results Relative to the Base Case

Table IV-1: Summary of Winter Sensitivity Results

Sensitivity	EORM	1:10
Base	24.25%	20.00%
A	29.50%	20.00%
A'	21.75%	20.00%
B	23.75%	20.00%
C	24.50%	20.00%
D	24.00%	17.50%
E	24.25%	20.50%
F	23.75%	19.50%
G	25.00%	21.25%
H	23.25%	18.50%

Short-Term Load Forecast Error

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.

For this sensitivity, short-term load forecast errors were used. This sensitivity resulted in the Winter EORM decreasing from 24.25% to 23.75%, 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.

Table IV-2: Short-Term Load Forecast Error

SHORT-TERM LOAD FORECAST ERROR	
LFE	Probability
4.87%	0.056
2.13%	0.222
0.00%	0.444
-1.42%	0.222
-1.92%	0.056

V. CONCLUSION

Winter reliability issues continue to drive the 2021 Reserve Margin Study results. However, it remains necessary to maintain 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, various changes could alter the dynamics of the system such that the primary risk shifts between seasons. Accordingly, it is recommended that the Winter TRM be established based on the results of the winter focused study and the Summer TRM be established based on the summer focused study, with minimum 1:10 LOLE threshold considerations applicable to both.

Winter Target Reserve Margin

The 2021 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 20.00% to ensure an adequate and cost-effective level of reliability on the System;
2. A reserve margin of 26% represents a risk-adjusted EORM at a range between the EORM and 85th confidence interval (the 85th percentile of risk – *i.e.*, VaR85);
3. Compared to the 24.25% expected case EORM, a 26.00% risk-adjusted EORM reduces VaR at the 85th confidence interval by $27.2M/year, while only increasing expected cost by $4.1M/year;
4. Compared to the 20.00% 1:10 LOLE threshold, a 26.00% risk-adjusted EORM reduces VaR at the 85th confidence interval by $108.8M/year and reduces expected cost by $35.1M/year; and
5. A 26% Winter TRM is consistent with results from the 2018 Reserve Margin Study, providing a stable planning metric.

Summer Target Reserve Margin

The Summer EORM from the summer focus study is 20.50%, with the VaR85 reserve margin being 23.25%. However, in a system where winter drives reliability results, 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 25%. However, in the event seasonal resources (such as winter-only resources) are made available, it may be possible to lower the Summer TRM below 25% - 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 15.75%, which is close to the currently approved Summer Target Reserve Margin.

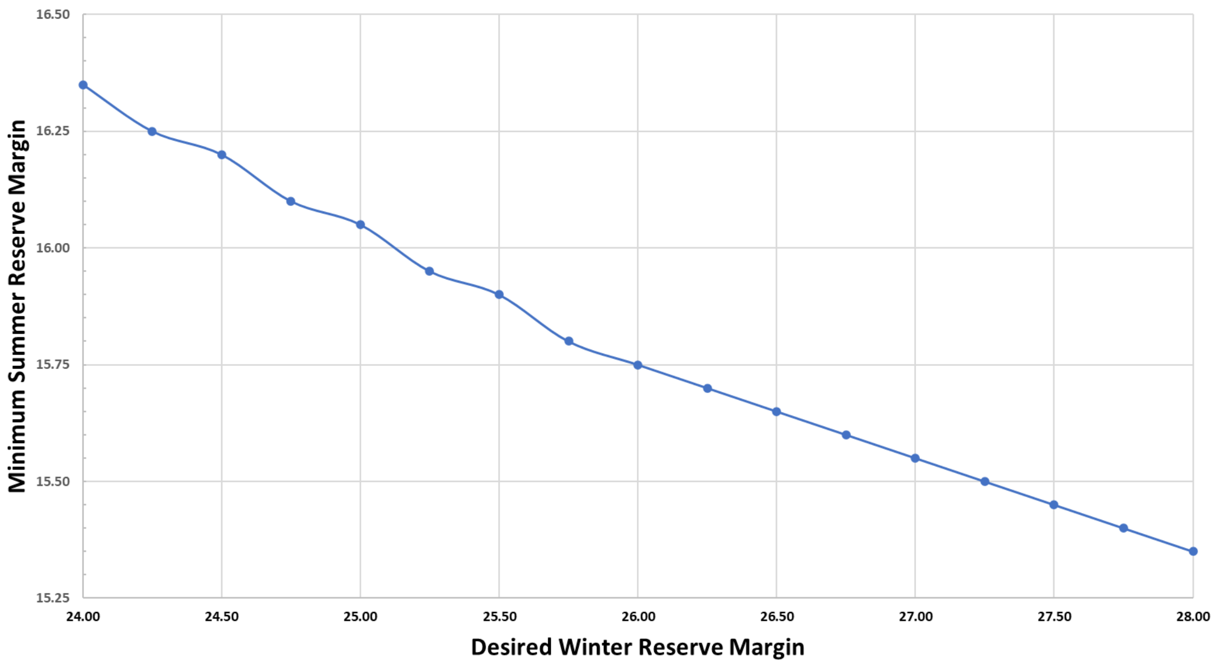

Figure V.1. Minimum Acceptable Summer Target Reserve Margins

In summary, the recommendation is to maintain the current Winter TRM of 26% for the System. This 26% Winter Target reflects the results of comprehensive economic study and a variety of other available information, and is extremely important in planning for resources that will meet customer needs in a reliable and cost-effective manner. It is further recommended that the current 16.25% Summer TRM also be retained, as there is no compelling reason to adjust the Summer TRM at this time. Moreover, the 16.25% minimum Summer TRM will ensure the combined summer and winter reserve margins remain at about the 1:10 LOLE Threshold.

These recommendations would apply for studies looking out four or more years. For studies looking inside a three-year window, the recommended Winter and Summer TRMs are 25.5% and 15.75%, respectively, reflecting a 0.5% reduction from each long-term TRM attributable to the difference between the long-term 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.