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Southern Company Energy Storage Study: A Study for the DOE Energy Storage Systems Program

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Abstract

This study evaluates the business case for additional bulk electric energy storage in the Southern Company service territory for the year 2020. The model was used to examine how system operations are likely to change as additional storage is added. The storage resources were allowed to provide energy time shift, regulation reserve, and spinning reserve services.

Several storage facilities, including pumped hydroelectric systems, flywheels, and bulk-scale batteries, were considered. These scenarios were tested against a range of sensitivities: three different natural gas price assumptions, a 15% decrease in coal-fired generation capacity, and a high renewable penetration (10% of total generation from wind energy).

Only in the elevated natural gas price sensitivities did some of the additional bulk-scale storage projects appear justifiable on the basis of projected production cost savings. Enabling existing peak shaving hydroelectric plants to provide regulation and spinning reserve, however, is likely to provide savings that justify the project cost even at anticipated natural gas price levels.

Transmission and distribution applications of storage were not examined in this study. Allowing new storage facilities to serve both bulk grid and transmission/distribution-level needs may provide for increased benefit streams, and thus make a stronger business case for additional storage.

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The authors appreciate the support of Southern Company leadership for this study. We appreciate the input of multiple members of Southern Company staff in providing us with useful information. Andy Sheppard, in particular, provided valuable insight into Southern Company's hydroelectric operations. Last, we appreciate the efforts of several of our colleagues at Sandia National Laboratories. Abbas Akhil was instrumental in the early stages of this work. Abe Ellis and Ross Guttromson provided valuable input at various stages of the project.

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EXECUTIVE SUMMARY

This study uses hourly production cost modeling to estimate the value of additional grid-scale electric energy storage in the Southern Company system as projected for 2020. The model represents Southern Company's expected generation fleet and load for 2020 and was built primarily from publicly-available system data supplied by Southern Company. This work takes into account the value of energy storage in providing energy time shift, regulation reserve, and spinning reserve to the bulk power system. Transmission and distribution applications, such as transmission line or substation capital upgrade deferral, were not examined.

The evaluation involved a number of different energy storage systems of differing sizes, ranging from larger pumped hydroelectric power plants to smaller bulk-scale battery systems. Since making forecasts involves uncertainty, the scenario storage systems were tested against a range of sensitivities: three different natural gas price assumptions, a 15% decrease in coal-fired generation capacity, and a high renewable penetration (10% of total generation from wind energy) scenario.

With the anticipated generation fleet and natural gas prices, additional bulk-scale energy storage does not appear to be justifiable on the basis of projected production cost savings. In the $10/MMBtu natural gas sensitivity, only the CAES project appeared to have a business case. In the $15/MMBtu natural gas sensitivity, nine of the sixteen storage scenarios appeared to have a business case. These two sensitivities specify that the natural gas price remain at these elevated levels essentially for the storage project lifetimes.

While additional storage becomes more attractive in the reduced coal-fired generation sensitivity,[1] system savings from additional storage are still well below levels that would provide economic justification for a project. Likewise, in the high renewable penetration sensitivity, the value of storage is enhanced, but is not enhanced enough to justify the project. While the large wind component requires additional synchronized and non-synchronized reserve, the size and low cost of the Southern Company generation fleet enables it to handle these demands with minimal additional cost.

However, enabling existing peak shaving hydroelectric plants to provide regulation (by enabling some of the plants to take Automatic Generation Control signals) and spinning reserve may be a project with a good business case. The savings resulting from this additional ancillary service capability are estimated to be roughly $5 million per year in the reference case. The study team believes that this is an interesting outcome that calls for more investigation.

Some important caveats are in order. First, the primary focus of this study was to calculate the annual system savings (compared to the reference case) of each scenario. In order to calculate the financial value of each project, we make the assumption that the annual savings calculated are a reasonable estimate of annual savings going forward. Annual savings going forward can differ from those calculated for 2020 mainly for the following reasons: (1) additional variable generation capacity could be installed or contracted for; (2) changes may be made to the conventional generation fleet over time; and (3) fuel prices may vary from those assumed for 2020.

[1] In this sensitivity, additional capacity was not added to the system to replace the 15% coal-fired generation capacity reduction.

Because they are based on the cost savings calculated for a single year, the study team does not believe that net present value (NPV) calculations in this report are highly accurate estimates of project value. Instead, the study team believes that the NPV calculations here are an indication of a project's potential benefit.

Second, the NPV calculations in this report are also sensitive to assumptions on the discount rate, inflation, and battery stack life and replacement cost (for those projects involving batteries). In this study, we assumed an 8% discount rate and a 2.5% inflation rate for all projects. For those involving batteries, we assumed a 15-year battery stack life, and that the stack replacement cost would be 60% of the initial project capital cost. Lower discount rates (and higher inflation rates) would make the projects seem more attractive than presented here. A shorter battery stack life or higher stack replacement cost would make projects involving batteries less attractive.

Third, this study uses an approximation of Southern Company's reserve specification. The specification of operating reserve is an important factor in how the system is dispatched, and will have an impact on the cost savings yielded by storage projects and new generator additions. Discrepancies in assumed versus actual operational reserve can be a source of error in storage value estimations.

Fourth, the model used for this analysis assumes that there will be no transmission constraints on the bulk power system of Southern Company in 2020. If, in fact, such constraints develop, then additional, properly-placed storage may be able to provide additional benefits by alleviating congestion. Likewise, if there are any areas where transmission capacity upgrades are being considered, storage could act to defer such upgrades. A determination of the level of benefits from transmission upgrade deferral was not part of this study.

Finally, this study does not consider the value of additional storage for distribution-level applications. A distribution value analysis would require additional work to identify possible distribution needs and to estimate the value of serving those needs. Allowing new storage facilities to serve both bulk grid and distribution-level needs may provide for increased benefit streams, and thus make a stronger business case for additional storage.

ACRONYMS

AC	alternating current
AGC	automatic generation control
CAES	compressed air energy storage
CC	combined cycle
CT	combustion turbine
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EPRI	Energy Power Research Institute
EWITS	Eastern Wind Integration and Transmission Study
GW	gigawatt
GWh	gigawatt hour
IGCC	integrated gasification combined cycle unit
kW	kilowatt
kWh	kilowatt hour
MMBtu	million British Thermal Unit
MW	megawatt
MWh	megawatt hour
NPV	net present value
NG	Natural Gas
PSH	pumped storage hydro
SNL	Sandia National Laboratories
TEPPC	Transmission Expansion Planning Policy Committee
VO&M	variable operation and maintenance
WECC	Western Electricity Coordinating Council

BACKGROUND

Southern Company approached Sandia National Laboratories (SNL) with a request to evaluate the business case for additional storage on their bulk power grid.

The SNL team proposed that the business case for storage could be best evaluated with a production cost model of the Southern Company system. The annual cost of producing power to meet load for the reference system (without additional storage) could then be compared with the cost of meeting load in several scenario cases with various types and sizes of additional storage. In order to allow for time for planning and construction of a storage facility (supposing a decision were made to construct such a facility), the system as projected in 2020 was selected for this study.

The Southern Company System

The Southern Company and its subsidiaries have been serving the Southeast for over 100 years. The Southern Company is made up of four electric utilities: Alabama Power, Georgia Power, Gulf Power, and Mississippi Power.

While Alabama Power and Georgia Power serve virtually all of Alabama and Georgia, the other two utilities serve portions of two other states: Gulf Power serves the Florida Panhandle and Mississippi Power serves southeast Mississippi. The combined service territory of these utilities is about 120,000 square miles (see Figure 1). Southern Company has more than 43,000 MW of generating capacity, and serves over 4 million retail customers [1].

Source: Southern Company Website

Figure 1. Southern Company service territory.

Southern Company is responsible for over 27,000 miles of transmission lines and 3,700 substations. In addition to the four regulated utilities, the Southern Company has two other subsidiaries that engage in power generation: Southern Power, a competitive wholesale generation business that operates in six southeastern states, and Southern Nuclear, which is the operator of Southern Company's three nuclear power plants (in Georgia and Alabama) [1].

In 2010, the percent of power generated by type of plant is illustrated in Figure 2, and is as follows: 58% by coal-fired generation, 25% by natural gas-fired generation, 15% by nuclear plants, and 2% by hydro plants [2].

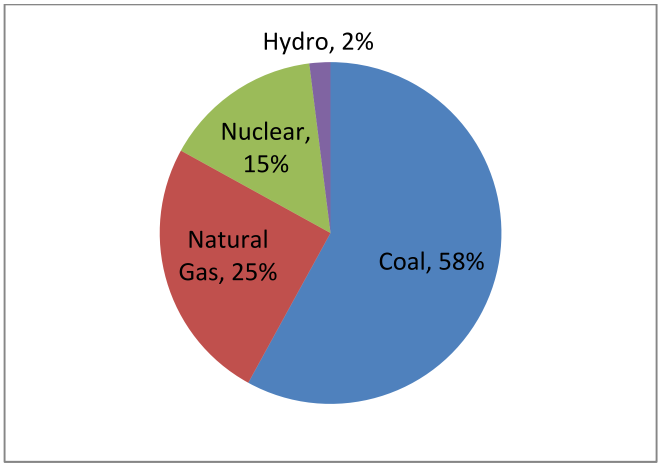

Figure 2. Southern Company 2010 generation by unit type.

Southern Company and its partners are constructing two new nuclear units at Vogtle Nuclear Power Plant near Waynesboro, Georgia. Each unit has a nameplate capacity of approximately 1,100 MW. The units are scheduled to begin operation in 2016 and 2017. The Vogtle plant is displayed in Figure 3.

Figure 3. Vogtle Nuclear Power Plant, near Waynesboro, Georgia.[2]

[2] Source: Nuclear Regulatory Commission, Vogtle operating license renewal application.

Southern Company and Wholesale Power Providers/Distribution Cooperatives

This study is concerned with the load the Southern Company serves, and with the resources they have at their disposal for serving that load. There are other load-serving entitles (LSEs) and wholesale power generation entities that operate within areas served by Southern Company. Southern Company is not responsible for balancing load and generation for these LSEs. Therefore, the model used in this analysis does not include generation owned by others, or load served by others. The following discussion of wholesale generation and electric cooperatives is intended to provide context, and is not an exhaustive discussion of all such entities operating in the areas Southern Company serves.

In Georgia, Oglethorpe power serves 39 Electric Membership Corporations providing electricity to more than 4.1 million people. It owns a diverse portfolio of power plants with a combined capacity of over 7,000 MW.[3] One asset in this portfolio is a 75% ownership of the Rocky Mountain Hydroelectric Plant, which is a roughly 1,100-MW pumped-storage facility near Rome, Georgia. Southern Company owns the remaining 25%. In this study, we consider only the 25% of the facility that Southern Company owns and controls.

MEAG Power has partial ownership in four power plants (Plant Hatch, Plant Vogtle, Plant Scherer, and the coal-fired Plant Wansley), and owns a portion of the Wansley Combined Cycle plant. It thus provides over 2,000 MW of wholesale power generation capacity to the 49 communities it serves throughout Georgia.[4]

The PowerSouth Energy Cooperative provides wholesale power to 16 electric cooperatives and four municipal electric systems in Alabama and northwest Florida. It has a combined generating capacity of 1,600 MW. Of note is that one of the generating facilities PowerSouth owns is the 110-MW Compressed Air Energy Storage (CAES) facility in McIntosh, Alabama.

In addition, the Tennessee Valley Authority provides wholesale power to eight electric cooperatives located in northern Alabama.[5]

Hydroelectric Production and Pumped Storage Hydro

While only about 2% of the total 2010 power production in 2010 was from hydroelectric generation, it nevertheless plays an important role in system operations.

Southern Company has multiple hydroelectric plants. Some of these are categorized as peak shaving plants, while others are categorized as run-of-river plants. Peak shaving plants have intra-day storage capability, and can thus be dispatched to produce power at the time of day it is most needed (usually coinciding with the daily peak). They are modeled here as having the ability to store 18 hours of river flow. Run-of-River plants have a more limited ability to shape their power output – they essentially must take river flows as they are for power production. They are modeled here as having the ability to store 3 hours of river flow.

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[3] Source: Oglethorpe Power website, http://www.opc.com/index.htm, accessed December 10, 2012.

[4] Source: MEAG Power website, http://www.meagpower.org/PowerGeneration/Facilities/tabid/70/Default.aspx, accessed December 10, 2012.

[5] Source: Alabama Rural Electric Association of Cooperatives website, http://www.areapower.coop/, accessed December 10, 2012.

In this study, hydroelectric generation is modeled in aggregate, with one generator representing all peak shaving hydro plants, and another representing all run-of-river plants. The run-of-river water inflows are highly seasonal, with high levels of flow January through April, and low levels from June through November. Water inflows to the peak shaving hydropower plants exhibit much less seasonality, and are in fact almost level throughout the year.

Southern Company owns 25% of the Rocky Mountain Pumped Storage Hydroelectric Plant (near Rome, Georgia), which amounts to roughly 275 MW of capacity. Southern Company also owns the Wallace Dam Pumped Hydro Project (located on the Oconee River in central Georgia), which pumps water from Lake Sinclair into Lake Oconee (created by Wallace Dam) for storage. Wallace Dam is actually both a pumped storage hydro facility and a conventional hydroelectric generating plant. It has six units (four of which are reversible) for a total nameplate generation capacity of 321 MW [3]. The pumped storage portion of the plant (the Wallace Dam Pumped Hydro Project) has an installed capacity of roughly 210 MW.

In the reference case of this model, as well as in all storage scenarios using that reference case as a base, the peak shaving, run-of-river, and pumped storage hydroelectric plants are not allowed to provide regulating or spinning reserve. The reason for this is that Southern Company personnel informed us that these hydroelectric plants cannot provide regulation (they do not currently have the capability to accept an automatic generation control [AGC] signal). Since they cannot provide regulation, Southern Company does not consider them as a part of their pool of generators capable of supplying spinning reserve. The study team did not investigate the level of effort required to enable some of the existing hydroelectric plants to take an AGC signal.

Renewable Energy (Non-Hydroelectric) and Southern Company

Only one wind farm of roughly 200-MW of capacity is assumed to be in operation in 2020. That wind farm is located in Oklahoma, outside of Southern Company's area of operations. For this study, it is assumed that Southern Company will receive power flows on transmission interties that directly correspond to the moment-to-moment generation of the wind farm. In other words, Southern Company must deal with this wind plant's variability of generation as if the wind plant were located within the boundaries of the Southern Company balancing authority area (BAA). It is also assumed that this power is procured through a fixed-price power purchase agreement (PPA), and that Southern Company is required to take all power produced.

None of the states that Southern Company operates in currently have a renewable portfolio standard. Without such legislation at either the state or federal level, it is unlikely that Southern Company would embark on a large-scale renewable generation construction program. The study team did perform a model sensitivity with wind supplying roughly 10% of total generation, in order to better understand whether such a level of renewables would improve the case for additional storage.

Southern Company Operating Reserves

This study assumes that the only operating reserve Southern Company keeps is contingency reserve. This reserve is assumed to be 1250 MW at all times, with at least 650 MW of spinning reserve, the remainder being quick start reserve. Of the 650 MW of spinning reserve, at least 500 MW must be regulating reserve, capable of accepting and acting on an AGC signal.

In reality, Southern Company may require higher levels of spinning reserves (regulation-capable or otherwise) when load is especially large or volatile. According to the utility, these additional spinning reserve amounts are small compared to the base level required, and are specified on an ad-hoc basis. The model used in this study therefore does not take into consideration such additional amounts of reserve.

With a coal- and gas-fired generation capacity of over 40,000 MW comprised of more than 175 units, there is no shortage of capacity for supplying the required level of reserves. Given the relatively low operational reserve requirement and relatively large reserve capacity available, the value of additional reserves is low.

Another ramification of this operational reserve requirement is that adding reserve-capable storage capacity above 650 MW is of no value in terms of providing reserve, since at no time is more than 650 MW of spinning/regulating reserve required.[6] Moreover, resources that can provide spinning but not regulating reserve add little value, since at least 500 MW of regulating reserve is required.

If there were a higher level of variable generation on the system, there would be the need to carry additional operating reserve (on top of levels specified for contingency reserve). The higher the level of reserve specified, the more costly it would be to supply this reserve, and the more value a reserve-capable storage system could provide.

[6] The exception to this is the high renewable penetration case, where spinning reserve requirements are usually higher than that required for contingency alone, and regulation and spinning reserve are mutually exclusive (in other words, the same MW of reserve capacity cannot count towards both the regulation and the spinning reserve requirement).

ANALYSIS APPROACH

Production Cost Model

For this study, the SNL team constructed a production cost model of the Southern Company system. The model solves for least-cost dispatch to meet load, adhering to the specified constraints. The overall approach is to compare the cost of producing power (to meet load) over a year in a reference case (the system as expected) versus a case with some addition or alteration to the system, such as an additional storage facility. Any reduction in cost as compared with the reference case is considered to be the annual savings from the scenario storage facility.

The production cost model used in this study was created in a commercial software package called PLEXOS. As of July 2011, there were more than 95 commercial clients using PLEXOS in 25 countries.[7] While there are competing production cost models available, the SNL team chose to use the PLEXOS software because of its flexibility, and what we believe is state-of-the-art simulation code.

Production cost models allow the user to specify unit characteristics (such as heat rate, ramp rate, minimum up time, etc.) for each generator. They also allow for data files on load and variable generation to be supplied. The user must then specify how often generation and load will be matched (whether hourly or some finer interval of time), how long the simulation is to be run (a month, a year, or multiple years), and whether the problem is to be optimized on a daily or weekly basis.[8] After a power system is specified in this way, the production cost model formulates the problem into a mathematical equation that is passed to a commercial solver. (In this study, the CPLEX Optimizer by IBM was used.)[9] The solver then solves the equations, which call for least-cost unit commitment and dispatch, subject to the generation unit constraints specified.

The model performs unit commitment and dispatch, while co-optimizing for energy and operating reserve. The model explicitly takes the specified reserve into account, and dispatches units to ensure that the reserve is provided. When deciding which units will carry, say, the required level of spinning reserve, the model will seek to obtain least-cost dispatch, taking in both energy and reserve requirements into account.

Generation is dispatched to meet load each hour in this study.

Optimization Horizon

A weekly optimization horizon was chosen for the runs in this report. Allowing for weekly optimization as opposed to daily optimization allows for more opportunity to use storage to save in production costs. Allowing the model to look over a week can, for example, allow it to find some block of time later in the week with unusually high demand, and determine that it would be

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7 Source: http://energyexemplar.com/software/plexos-desktop-edition/,accessed December 13, 2012.

8 These are some of the most important settings, in the view of the authors. In reality, there are many other settings to choose from, such as how many linear segments to use in approximating heat rates that were described by polynomials.

9 For more information on the CPLEX Optimizer, see http://www-01.ibm.com/software/integration/optimization/cplex-optimizer/, accessed December 13, 2012.

better to save energy (in a pumped storage hydro plant, for example) in anticipation of this event than to optimize performance over a 24-hour period.

Given the low levels of variable generation that Southern Company has contracted for, and that load forecasting is in general quite accurate, the SNL team believes that weekly optimization provides a better representation of their system than daily optimization. We would like to note that weekly optimization not only improves the performance of hypothetical storage added to the system, it also improves the performance of existing storage.

Zonal Nature of Model

For this study, it is assumed that there are no constraints on the bulk power transmission system. Given this assumption, the SNL team felt that using a zonal model, which does not model individual transmission lines, would be a sufficient representation of the system. In a zonal model, all generation units are allowed to be dispatched (within the specified unit constraints) to achieve least-cost generation, and the assumption is made that there are no transmission constraints that would require a deviation from least-cost dispatch.

Model Dataset

Normally, a production cost model would be created using the same generation unit characteristics the utility uses in its planning process. Southern Company chose not to provide the SNL team with this data. Instead, the team at Southern Company created a new dataset, relying on public sources (in this case, SNL Energy – which is not affiliated with Sandia National Laboratories) for data. They also included some of their own estimates where the public source data was incomplete. In this dataset, units of the same category (large coal units, for example) generally have the same heat rate and other key characteristics.

At the same time, actual load data from 2010 was provided and was scaled up to reflect Southern Company load projections for 2020. Actual 2010 monthly water inflow data was provided for the two main categories of hydroelectric plants – peak shaving and run-of-river.

For the high renewable penetration sensitivity, 2004 EWITS data was used. Since Southern Company currently has no plans to add this much wind generation, the study team identified several sites in the southern portion of the Great Plains. These sites were geographically distributed, capable of supporting various amounts of wind generation, and part of the Eastern Interconnect. Data from 2004 was chosen because 2004 was a leap-year, as 2020 will be – therefore, no assumptions were needed for output on February 29. Because of the large amount of wind generation in this sensitivity, the study team was concerned that any errors in creating data for February 29 from a non-leap-year dataset could impact the results. More information on how the wind generation dataset for the high renewable penetration sensitivity runs was assembled can be found in Appendix D.

For all of the other sensitivities, there is only one wind generator that provides power to Southern Company. The Chisholm View wind farm, at roughly 200 MW of installed capacity, provides about 0.3% of the total amount of generation in these runs. Simulated 2006 wind generation data from the Eastern Wind Integration and Transmission Study (EWITS) dataset was used for the Chisholm View wind farm in these runs.

Even though the high renewable penetration sensitivity runs use 2004 wind data, and all other sensitivity runs use 2006 wind data, the results can be compared. Within each sensitivity, we are comparing the reference run to the scenarios in that sensitivity to obtain a cost difference. This level of cost savings for each scenario can be compared across the sensitivities, even when the reference runs of those sensitivities are at dramatically different cost levels.

One area of the study dataset not supplied by Southern Company was the unit start costs. While estimating the fuel cost used on startup is relatively straightforward, estimating the wear-and-tear on equipment because of startups is much more difficult. An important source of value for bulk storage can be in serving to decrease the number of unit starts. In order to assess how much decreased unit starts are worth, it is important to take into account an estimate of the additional maintenance cost each start imposes on a unit. Therefore, the SNL team used estimates calculated by the consultancy APTECH for the non-fuel start cost for seven different types of generation units, and assigned each natural gas and coal-fired unit in the Southern Company fleet a non-fuel start cost [4].

Study Methodology Strengths and Limitations

A strength of this study is that it uses a production cost model to estimate what level of savings might accrue to the grid from a new storage facility.

The model can represent system unit commitment and dispatch at the bulk power level, and thus provide informed estimates of how changes to the system may impact actual operational cost. Actual load and renewable generation profiles can be read into the model as data files, adding realism to the simulation. The model can be calibrated to mimic actual unit dispatch order when that dispatch order differs from what one might expect from a strictly economic dispatch. Savings from decreased unit starts, operating low-cost plants at a more efficient loading point, and less marginal unit dispatch are all effects that production cost modeling can capture.

An alternative approach could be taking market data on energy and reserve prices on an hourly basis, assuming that storage would not be large enough to impact these prices, and calculating the revenues that such a storage facility might be able to realize by offering energy time-of-day shifting and reserve. In this case, market pricing is not available. Moreover, the scenario storage facilities are large enough that they would likely impact prices.

Some of the limitations of this study are that it uses a dataset that differs from that used internally by Southern Company for planning purposes, and that it assumes there are no transmission constraints on the Southern Company system.

The unit characteristics dataset used to construct the production cost model used in this study is not the same as Southern Company uses for their own internal planning purposes. The Southern Company team assured us that the dataset they provided was a reasonable representation of their system. Nevertheless, one must assume that the dataset used by the Southern Company planning team is a more detailed and accurate representation. The cost differences in the production cost model runs presented in this report, therefore, are best viewed as being indicative of the value various storage units might be able to achieve – rather than as highly accurate calculations of this value.

In addition, this model does not calculate power flows and take transmission constraints into consideration. Even if Southern Company has no transmission constraints currently, such constraints could develop in the future. In this case, grid-level storage could provide additional benefits by acting to mitigate that constraint, and therefore serve to defer or eliminate the need for transmission system improvements. If a transmission constraint were to develop, the valuations for storage presented here would likely underestimate their actual value to the system.

STUDY SETUP

System Assumptions

Table 1 indicates the assumptions utilized in this analysis and their source.

Table 1. Base System Assumptions.

	Assumption	Detail	Source
1	*Load aggregated into hourly load*	aggregated by average in the hour	
2	*Fuel Price Assumptions*	Coal: $2.93/MMBtu	*EIA for 2020*
		Natural Gas: $5.70/MMBtu	*EIA for 2020*
		Oil: $28.467/MMBtu	*EIA for 2020*
		Uranium: $0.67/MMBtu	*WECC TEPPC (Transmission Expansion Planning Policy Committee)*
		Landfill Gas: $2/MMBtu	*NW Power Council: 6th NW Power Plan*
		Wood: $1.6/MMBtu	*NW Power Council: 6th NW Power Plan*
		Coal IGCC: $0.97/MMBtu	*33% of coal price*
3	*Run Up Rate*	Nuclear: 0.5 MW/min CC: 45 min from 0 -> max capacity	*EU Joint Research Centre: Load-following operating mode at Nuclear Power Plants (NPPs) and incidence on Operation and Maintenance (O&M) costs*
4	*Ramp Rates Ignored*	Assumed that units can ramp from min up to max capacity within the hour	
5	*Start Costs (Fuel cost)*	Assumed that main fuel is starting fuel. Fuel required to start is the amount of fuel required to reach min capacity.	
6	*Start Costs (Fixed cost)*	Based on APTECH TEPPC update accounting for labor, unit wear and tear and other factors	*APTECH TEPPC Update for WECC TEPPC* [4]
7	*Nuclear O&M Charges*	VO&M: $0.42/MWh	*MIT 2003 "Future of Nuclear Power" Study updated numbers for 2009*
		FO&M: $96/kW/yr	
8	*Mean Time to repair outage*	96 hours for nuclear units, 48 hours for all other units	

Storage Scenarios

Table 2 presents the scenarios studied. The SNL and Southern Company teams worked jointly to develop these based on a consideration of system generation units, peak and off-peak demand, demand seasonality and reserve requirements.

Table 2. Energy Storage Scenario Key.

Scenario	Additional Storage	Capacity (MW)	Storage (hr)	Round-Trip (AC-AC) Efficiency (%)
s1	PSH	800	8	81%
s2	PSH	800	16	81%
s3	PSH	1600	8	81%
s4	PSH	3200	8	81%
s5	CAES	800	8	74%
s6	Cryogen	800	8	50%
s7	Cryogen	800	16	50%
s8	Flywheel	100	0.25	85%
s9	Battery	500	4	90%
s10	Battery	500	7	75%
s11	Battery	100	4	90%
s12	Battery	100	1	90%
s13	PSH	1600	8	81%
	Battery	100	1	90%
s14	PSH	1600	8	81%
	CAES	800	8	74%
s15	PSH	3200	8	81%
	Battery	500	4	90%
s16	Flywheel	100	0.25	85%
	Battery	500	4	90%
s17	Extra CC unit	840	-	-
s18	Peak shaving spin	500	-	-

Each of these scenarios makes a change to the reference system. Except for scenarios 17 and 18, they all involve adding energy storage. The scenarios are independent. Scenario 2, for example, adds 800 MW of pumped storage hydro (PSH) capacity (with 12,800 MWh, or 16 hours, of storage) to the reference system; it does not add the 800 MW of new pumped storage capacity to Scenario 1. An important note with the size of these scenarios is that they do not necessarily represent a single storage resource. For example, Scenario 9 could consist of a single 500-MW battery system, or five 100-MW systems. If there were transmission or distribution constraints, an appropriate distribution of the storage resource may allow for the provision of services beyond those benefitting the bulk grid.

The round-trip efficiencies of each of the storage facilities are reflected in the production cost model. The round-trip efficiency is an important factor in determining how often a storage facility is used. With the exception of the cryogen facility, the efficiencies shown in Table 2 are derived from information in the SNL Electric Power Research Institute (EPRI) *Energy Storage Handbook* [5]. For the cryogenic storage system, Highview Power Storage (the system provider) states that the round-trip efficiency of a stand-alone facility is around 50%.[10] If the facility were co-located with an industrial process providing waste heat, then Highview claims that the round-trip efficiency would be about 70%.[11]

All scenario storage facilities are allowed to participate in offering operating reserves (regulation, spinning, and quick start reserve) as well as energy. One exception is the flywheel storage facility, which only provides regulation reserve as its storage capacity is limited to 15 minutes at full power output.

Model Sensitivities

The base case sensitivity uses a natural gas price of $5.70/MMBtu for 2020. There are many natural gas price forecasts for 2020. The Transmission Expansion Planning Policy Committee (TEPPC) that is a part of the Western Electricity Coordinating Council (WECC), for example, uses a price of $5.59/MMBtu in its TEPPC 2022 Common Case. Since part of the value of bulk energy storage is its ability to provide time-of-day shifting, thereby decreasing the price of on-peak power, it is prudent to evaluate the possibility of a variance in this price assumption. Therefore, all scenarios are evaluated at natural gas prices of $5.70/MMBtu, $10/MMBtu, and $15/MMBtu.

There is a possibility that stricter environmental regulations may lead to some of Southern Company's coal-fired power plants not being available. This work examines the effect on the value of energy storage resources of a 15% reduction in the capacity of coal-fired generation. This unavailable capacity is not replaced with new generation in this study. A final sensitivity specifies a large amount of additional wind generation capacity, such that Southern Company generates roughly 10% of its power from wind in 2020. This is termed the high renewable penetration sensitivity. While this is not something Southern Company believes is likely to happen, it is within the realm of possibility that state governments where they operate or the Federal government might decide to adopt a renewable portfolio standard that would force them in this direction. Other generation units on the Southern Company system are left unchanged in this sensitivity.

10 Source: Highview Power website, http://www.highview-power.com/wordpress/?page_id=1405, accessed December 11, 2012.

11 Source: Highview Power website, http://www.highview-power.com/wordpress/?page_id=8, accessed December 11, 2012.

MODEL RESULTS

Base Model Results

System Reference Model for 2020

APPENDIX A describes the verification process for the reference model of the Southern Company system. This section establishes the baseline generation, load, and cost profile for the system. Table 3 indicates the reference model characteristics. As explained in APPENDIX A, the project validated system load and dispatch, but not cost figures, and thus these are representative figures not in line with actual costs.

Table 3. Reference System Model Characteristics.

Reference System	Characteristics
Customer Load (GWh)	230,000
Peak Load (MW)	42,000
Available Energy (GWh)	420,000

The system generation breakdown is given in Table 4. Coal provides about 53% of total system generation, natural gas 25%, and nuclear power 19%.

Table 4. Reference System Generation Breakdown.

Generation Type	Generation (%)
Coal	53%
Natural gas	25%
Nuclear	19%
Hydroelectric	2%
Renewables	1%

Energy Storage Scenario Results

This section indicates the value the selected energy storage systems present to the Southern Company power system. The value to the system from a storage facility is considered to be the reduction in overall system operating costs due to that storage facility. This reduction in system cost can be broken down into a reduction in system generation costs and a reduction in unit start costs. The savings in providing reserves are manifested as a combination of generation and unit start savings. This is discussed in further detail below.

The system savings presented in this section result from the use of scenario energy storage. The values calculated apply to the system as it is represented for 2020. Changes in generation fleet characteristics and composition, as well as changes in load, will impact the calculated system savings.

Generation cost is the cost to generate power once a unit is synchronized and producing power. Total generation cost includes generation cost, but adds unit start cost. Unit start cost is generally made up of a variable component (to take into account fuel cost) and a fixed component (to reflect additional maintenance expense related to the wear-and-tear on equipment associated with each startup).

Pumped Hydro Systems

Four of the 18 scenarios involve adding pumped hydroelectric energy storage alone. Table 5 indicates system changes relative to the reference case. As additional pumped hydro storage capacity increases (from 800 MW in Scenario 1 to 1600 MW in Scenario 3 to 3200 MW in Scenario 4), there is an increased reduction in system generation costs and in system start and shutdown costs. This results in a total savings for Scenario 1 at $23 million to $58 million for Scenario 4. As may be expected, these results indicate decreasing marginal returns.

A seeming anomaly in the value provided by the different sizes of PSH facilities is that adding an additional 8 hours of storage to the Scenario 1 PSH facility leads to only a small increase in savings. While doubling PSH capacity adds substantial value, doubling storage volume does not. This seems to be because storage capacity is used to shave the daily peak; having 16 hours of storage is well beyond what is required for this, and therefore cannot be profitably used.

Table 5. Pumped Hydro Scenario System Savings.[12]

Scenario	Generation Cost ($mil 2020)	Generator Start Cost ($mil 2020)	Total Generation Cost ($mil 2020)
s1 800/8	(15.2)	(7.4)	(22.6)
s2 800/16	(16.5)	(7.4)	(23.9)
s3 1600/8	(27.7)	(12.1)	(39.8)
s4 3200/8	(38.6)	(19.3)	(57.9)

Since these scenario storage facilities provide both time-of-day shifting and operating reserves, it is difficult to determine the fraction of value provided by each without doing additional analysis. For Scenarios 1 and 4, the team ran the model a second time, with the scenario storage facilities not allowed to provide reserve. Compared with the runs with reserves enabled, the savings was about $0.1 million less in Scenario 1, and $1.2 million less in Scenario 4. We can therefore conclude that the overwhelming majority of the value provided by these two scenario storage projects is from energy time-of-day shifting, and not from the provision of reserve. More discussion about the need for reserve in the Southern Company system can be found at the end of this section.

[12] Note: Positive values represent an increase relative to the reference, and negative values (which are in parentheses) represent a savings relative to the reference.

Table 6 and Table 7 indicate the effects of the different energy storage systems on generation and generation costs, and on unit starts and unit start costs. In general, the energy storage systems enable increased coal and combined cycle (CC) generation while reducing gas combustion turbine (CT) generation, leading to efficiency increases and fuel cost savings.

Table 6. Scenario Effect on Unit Generation Relative to Reference System.

Generation (GWh)			
Scenario	Coal	CC	CT Gas
s1 800/8	462	279	(462)
s2 800/16	534	219	(448)
s3 1600/8	513	723	(724)
s4 3200/8	623	1,249	(978)

Table 7. Scenario Effect on Generation Costs Relative to Reference System.

Generation Cost ($mil 2020)			
Scenario	Coal	CC	CT Gas
s1 800/8	11.4	5.1	(31.7)
s2 800/16	13.5	(0.7)	(30.7)
s3 1600/8	6.2	15.8	(49.7)
s4 3200/8	3.3	25.2	(67.1)

Additionally, Table 8 and Table 9 highlight a significant reduction in unit starts for each category of these units: coal, combined cycle, and simple cycle gas turbines. The storage systems replace peaking power and reserve requirements that simple cycle gas turbines otherwise provide in the reference case. They also reduce the incidence of unit starts for the coal and combined cycle units, allowing for more efficient operation.

Table 8. Scenario Effect on Unit Starts Relative to Reference System.

Unit Starts			
Scenario	Coal	CC	CT Gas
s1 800/8	(38)	(35)	(712)
s2 800/16	(46)	(32)	(660)
s3 1600/8	(96)	(43)	(1,166)
s4 3200/8	(153)	(81)	(1,735)

Table 9. Scenario Effect on Unit Start Costs Relative to Reference System.

Start Costs ($mil 2020)			
Scenario	Coal	CC	CT Gas
s1 800/8	(0.8)	(1.9)	(4.7)
s2 800/16	(1.1)	(1.7)	(4.7)
s3 1600/8	(2.0)	(2.2)	(7.9)
s4 3200/8	(3.4)	(4.6)	(11.3)

Figure 4 indicates the hourly daily average operational profile for the pumped storage units in Scenarios 1 through 4 as well as system load for the summer months of June through August. Two different vertical axes are used in this graph: the right-hand axis applies to the Load line (in orange) only, and the left-hand axis applies to all of the other lines shown. Here, the load is a seasonal average of the load in each hour, and is expressed as a percent of the annual peak load. Hour 1 is from 12:00am to 1:00am, and hour 24 is from 11:00pm to 12:00am. Storage system operation follows the load profile, with nighttime charging when load is low and daytime discharging at peak load.

APPENDIX C includes operational profiles for other seasons in the year.

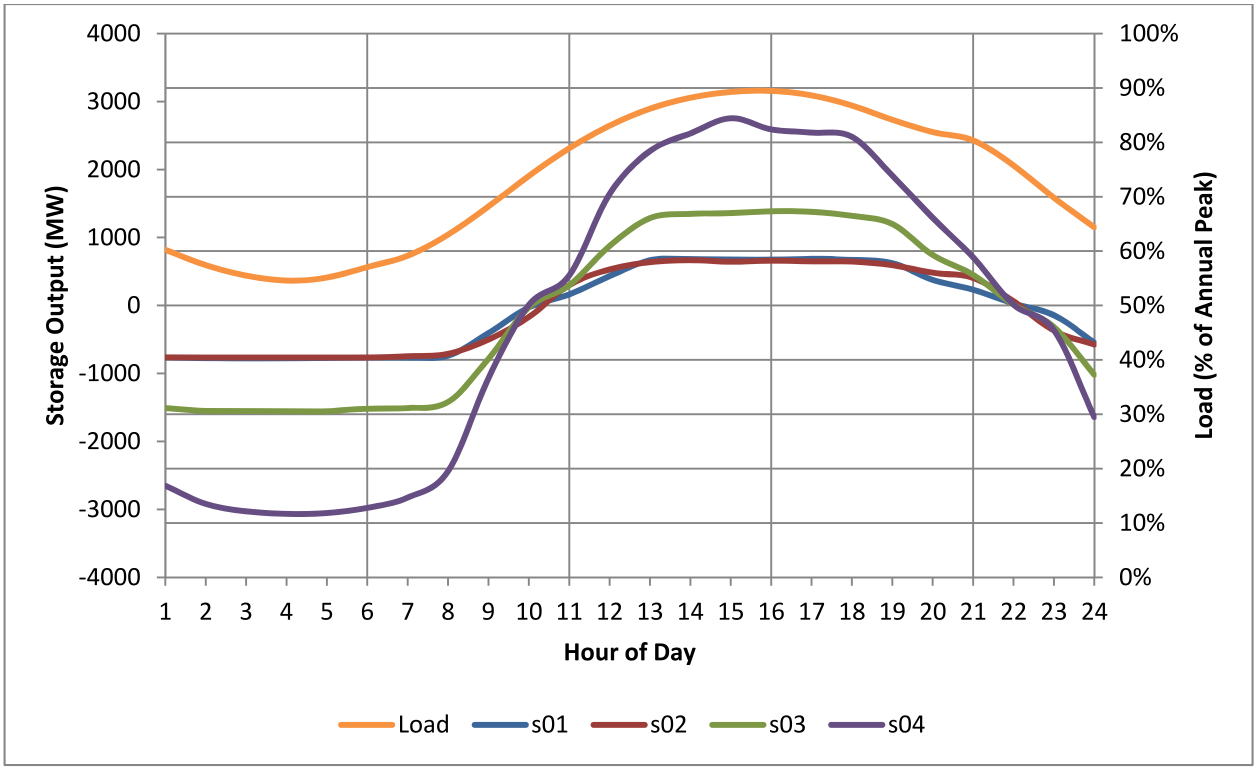

Figure 4. Daily average operation by hour of the pumped hydro storage systems modeled in Scenarios 1 through 4 for the summer months of June through August.

Compressed Air and Cryogenic Energy Storage

Table 10. Compressed Air and Cryogenic Energy Storage System Savings.[13]

Scenario	Generation Cost ($mil 2020)	Generator Start Cost ($mil 2020)	Total Generation Cost ($mil 2020)
s5 800/8	(9.6)	(6.1)	(15.7)
s6 800/8	(2.2)	(5.0)	(7.2)
s7 800/16	(1.2)	(5.3)	(6.5)

Scenario 5 uses an 800-MW CAES system. As in the case of the pumped hydro systems, it reduces system costs significantly relative to the reference, again with the value largely arising from a reduction in generation costs and generator start costs. Scenario 6 is the cryogenic air liquefaction system, with 50% efficiency, and as a result it performs less well than the more efficient CAES unit. Scenario 7 doubles the storage capacity of the 800-MW cryogen unit from 8

[13] Note: Positive values represent an increase relative to the reference case, and negative values (which are in parentheses) represent a savings relative to the reference case.

hours to 16 hours. This 16-hour unit, as utilized by the model, provides less value to the system than the 8-hour unit.

Table 11 and Table 12 indicate the effects of the energy storage systems on generation and generation costs. As before, Scenario 5 increases coal and combined cycle generation while reducing gas combustion turbine generation, leading to considerable efficiency increases and fuel cost savings, thereby reducing system generation costs. Scenarios 6 and 7, however, reduce coal and combustion turbine generation, increasing combined cycle generation. Their value arises from a reduction in coal and combustion turbine generation costs, despite an increase in combined cycle generation costs.

Table 11. Scenario Effect on Unit Generation Relative to Reference System.

Generation (GWh)			
Scenario	Coal	CC	CT Gas
s5 800/8	317	431	(436)
s6 800/8	(77)	522	(365)
s7 800/16	(51)	498	(364)

Table 12. Scenario Effect on Generation Costs Relative to Reference System.

Generation Cost ($mil 2020)			
Scenario	Coal	CC	CT Gas
s5 800/8	6.5	13.2	(30.0)
s6 800/8	(5.9)	28.8	(25.2)
s7 800/16	(4.4)	28.3	(25.2)

Additionally, Table 13 and Table 14 highlight a reduction in unit starts for each category of the units indicated. The storage systems replace peaking power and reserve requirements that simple cycle gas turbines otherwise provide in the reference case. They also reduce the incidence of unit starts for the coal and combined cycle units, allowing for lower-cost operation.

Table 13. Scenario Effect on Unit Starts Relative to Reference System.

Unit Starts			
Scenario	Coal	CC	CT Gas
s5 800/8	(34)	(23)	(672)
s6 800/8	(23)	(8)	(670)
s7 800/16	(21)	(12)	(664)

Table 14. Scenario Effect on Unit Start Costs Relative to Reference System.

Start Costs ($mil 2020)			
Scenario	Coal	CC	CT Gas
s5 800/8	(0.4)	(1.2)	(4.5)
s6 800/8	(0.3)	(0.5)	(4.2)
s7 800/16	(0.3)	(0.7)	(4.3)

Flywheel and Battery Systems

Scenario 8 is a large 100-MW flywheel system, while Scenarios 9 through 12 are different battery storage systems. Table 15 indicates system changes relative to the reference case. The Scenario 9 system provides the most value as a 500-MW 4-hour battery. This may be a single unit, or distributed across the multiple units. Scenario 10's less efficient battery[14] and Scenario 11 and 12's smaller power rating batteries prove to be of less value to the power system.

Scenario 8 adds little value to the system.

Table 15. Flywheel and Battery Storage Savings.[15]

Scenario	Generation Cost ($mil 2020)	Generator Start Cost ($mil 2020)	Total Generation Cost ($mil 2020)
s8 100/0.25	(0.1)	(0.2)	(0.3)
s9 500/4	(7.4)	(4.3)	(11.7)
s10 500/7	(6.4)	(3.8)	(10.2)
s11 100/4	(1.2)	(0.3)	(1.5)
s12 100/1	(1.4)	(1.2)	(2.6)

[14] The battery in Scenario 10 is assumed to be a Sodium Sulfur battery, which has a larger storage capacity (7 hours as compared to 4) but a lower efficiency than a Lithium Ion battery (75% as compared with 90%).

[15] Note: Positive values represent an increase relative to the reference case, while negative values (which are in parentheses) represent a savings relative to the reference case.

Table 16 and Table 17 indicate the effect of the different energy storage systems on generation and generation costs. In general, the battery energy storage systems provide value through a reduction in gas combustion turbine costs. Cheaper coal and combined cycle energy replaces combustion turbine production. The flywheel system provides value by reducing combustion turbine and combined cycle generation and increasing lower cost coal generation. This reduces both combined cycle and combustion turbine generation costs.

Table 16. Scenario Effect on Unit Generation Relative to Reference System.

Generation (GWh)			
Scenario	Coal	CC	CT Gas
s8 100/0.25	137	(95)	(39)
s9 500/4	260	47	(257)
s10 500/7	352	125	(283)
s11 100/4	46	20	(55)
s12 100/1	82	1	(82)

Table 17. Scenario Effect on Generation Costs Relative to Reference System.

Generation Cost ($mil 2020)			
Scenario	Coal	CC	CT Gas
s8 100/0.25	5.5	(2.9)	(2.6)
s9 500/4	7.5	1.0	(17.8)
s10 500/7	10.1	1.9	(19.5)
s11 100/4	1.4	0.9	(3.8)
s12 100/1	2.9	1.3	(5.7)

Table 18 and Table 19 highlight a reduction in unit starts for each category of the selected generation units, leading to a reduction in start costs. Relative to generation cost reductions, these numbers are small. The storage systems provide peaking power and reserve requirements that simple cycle gas turbines otherwise provide in the reference case. They also reduce the incidence of unit starts for the coal and combined cycle units, either by providing peak energy when necessary, or charging to prevent unit shutdown, decreasing start costs.

Table 18. Scenario Effect on Unit Starts Relative to Reference System.

Unit Starts			
Scenario	Coal	CC	CT Gas
s8 100/0.25	0	(6)	(11)
s9 500/4	(20)	(12)	(490)
s10 500/7	(18)	(10)	(475)
s11 100/4	0	4	(99)
s12 100/1	(8)	(2)	(108)

Table 19. Scenario Effect on Unit Start Costs Relative to Reference System.

Start Costs ($mil 2020)			
Scenario	Coal	CC	CT Gas
s8 100/0.25	(0.1)	(0.3)	0
s9 500/4	(0.3)	(0.7)	(3.3)
s10 500/7	(0.1)	(0.5)	(3.2)
s11 100/4	0.1	0.2	(0.6)
s12 100/1	(0.3)	(0.1)	(0.8)

Figure 5 indicates the hourly daily average operational profile for the flywheel and battery units for the summer months of June through August (these curves are plotted against the left-hand vertical axis). This is compared against the average hourly system load in those same months. The average hourly load is represented by the orange line, and is plotted against the right-hand vertical axis. The average hourly load is expressed in percent of the annual peak load, which is the hour in the year with the highest load.

The operation of the storage systems follows the load profile closely, with nighttime charging when load is low to daytime discharge at peak load. APPENDIX C includes profiles for other seasons throughout the year.

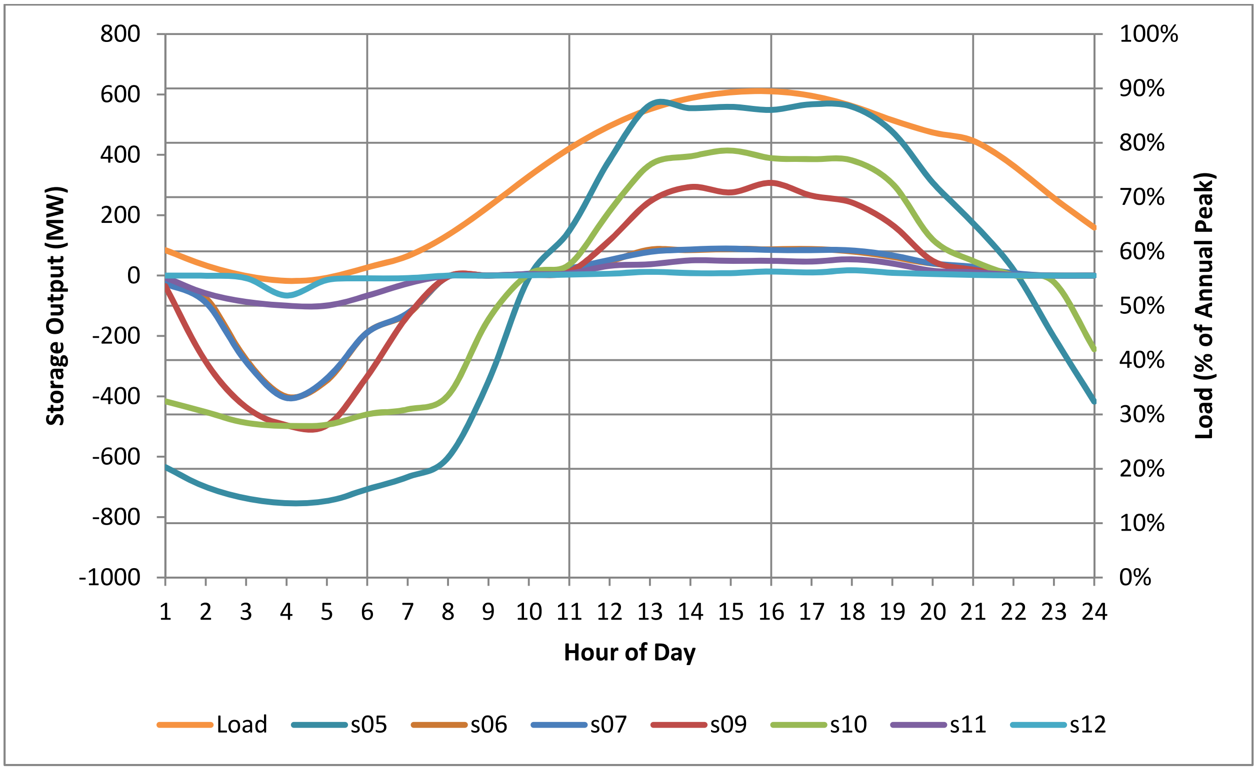

Figure 5. Daily average operation by hour of the flywheel and battery systems modeled in Scenarios 5 through 12 for the summer months of June through August.

Joint Storage Unit Scenarios

Amongst the results presented in Table 20, Scenario 15 (the 3200-MW/8-hour pumped hydropower system with the 500-MW/4-hour battery) provides the highest total generation cost savings, accounting for the highest generation cost savings as well as start cost savings for any evaluated unit. Scenarios 13 and 14 also perform well. Scenarios 13 and 14 both specify a 1600-MW/8-hour pumped hydropower system, in conjunction with a 100-MW/1-hour battery in Scenario 13, and an 800-MW/8-hour CAES in Scenario 14. Scenario 16, combining 100 MW of flywheel capacity with a 500-MW/4-hour battery storage system, is the worst performer of the group, though it still provides system savings.

Table 20. Multi-Unit Storage Scenario Savings. Positive values represent an increase relative to the reference, negative values in parentheses represent a savings relative to the reference.

Scenario	Generation Cost ($mil 2020)	Generator Start Cost ($mil 2020)	Total Generation Cost ($mil 2020)
s13 1600/8 & 100/1	(27.3)	(13.0)	(40.3)
s14 1600/8 & 800/8	(30.0)	(16.4)	(46.4)
s15 3200/8 & 500/4	(41.4)	(20.7)	(62.1)
s16 100/0.25 & 500/4	(8.4)	(3.9)	(12.3)

Table 21 and Table 22 highlight the effect of these different energy storage scenarios on generation and generation costs. As before, the energy storage systems enable increased coal and combined cycle generation while reducing gas combustion turbine generation, leading to an overall system operational efficiency increase and fuel cost savings, either by providing peak energy when necessary, or charging to prevent unit shutdown, decreasing start costs.

Table 21. Scenario Effect on Unit Generation Relative to Reference System.

Generation (GWh)			
Scenario	Coal	CC	CT Gas
s13 1600/8 & 100/1	494	754	(724)
s14 1600/8 & 800/8	689	891	(855)
s15 3200/8 & 500/4	553	1,389	(1,049)
s16 100/0.25 & 500/4	168	165	(282)

Table 22. Scenario Effect on Generation Costs Relative to Reference System.

Generation Cost ($mil 2020)			
Scenario	Coal	CC	CT Gas
s13 1600/8 & 100/1	4.7	17.6	(49.7)
s14 1600/8 & 800/8	9.9	18.4	(58.6)
s15 3200/8 & 500/4	(0.8)	29.6	(72.0)
s16 100/0.25 & 500/4	3.0	6.4	(19.6)

Table 23 and Table 24 indicate a reduction in unit starts for each category of the units observed. The storage systems replace peaking power and reserve requirements that simple cycle gas turbines otherwise provide in the reference case, leading to a reduction in starts and savings in their start costs. They also reduce the incidence of unit starts for the coal and combined cycle units.

Table 23. Scenario Effect on Unit Starts Relative to Reference System.

Unit Starts			
Scenario	Coal	CC	CT Gas
s13 1600/8 & 100/1	(96)	(55)	(1,208)
s14 1600/8 & 800/8	(120)	(73)	(1,513)
s15 3200/8 & 500/4	(170)	(84)	(1,860)
s16 100/0.25 & 500/4	(21)	(10)	(466)

Table 24. Scenario Effect on Unit Start Costs Relative to Reference System.

Start Costs ($mil 2020)			
Scenario	Coal	CC	CT Gas
s13 1600/8 & 100/1	(1.9)	(3.0)	(8.0)
s14 1600/8 & 800/8	(2.5)	(4.1)	(9.9)
s15 3200/8 & 500/4	(3.9)	(4.8)	(12.0)
s16 100/0.25 & 500/4	(0.4)	(0.5)	(3.0)

Non-Storage System Modifications

Scenario 17 is the addition of a new combined cycle natural gas power plant with a capacity of 840 MW. Scenario 18 allows the existing peak shaving hydro units to provide up to 500 MW of regulation and spinning reserve. Currently, these resources are not equipped with an AGC signal, and are not capable of providing regulation or spinning reserve. Table 25 indicates that Scenario 17 achieves a total of $32 million in savings, whereas Scenario 18 achieves $4.8 million in savings. It is important to recognize the difference in capital costs required to realize each scenario, significant for Scenario 17 with a new build of a natural gas combined cycle unit, and relatively minimal in Scenario 18 with proper controls enablement.

Table 25. Non-Storage Scenario System Effects. Positive values represent an increase relative to the reference, negative values in parentheses represent a savings relative to the reference.

Scenario	Generation Cost ($mil 2020)	Generator Start Cost ($mil 2020)	Total Generation Cost ($mil 2020)
s17 CC unit	(28.3)	(3.3)	(31.6)
s18 Current PS Spin	(2.0)	(2.8)	(4.8)

Table 26 and Table 27 indicate the effect of both scenarios on generation and generation costs. The new combined cycle unit replaces coal and combustion turbine generation, leading to overall cheaper system generation. Allowing the peak shaving unit to provide spinning reserve reduces the costs of combustion turbine generation more than it increase the generation and costs of coal and combined cycle units. As before, this is due to the reduced need to operate combustion turbine units for reserve requirements.

Table 26. Scenario Effect on Unit Generation Relative to Reference System.

Generation (GWh)			
Scenario	Coal	CC	CT Gas
s17 CC unit	(1,638)	2,047	(417)
s18 Current PS Spin	52	218	(270)

Table 27. Scenario Effect on Generation Costs Relative to Reference System.

Generation Cost ($mil 2020)			
Scenario	Coal	CC	CT Gas
s17 CC unit	(70.5)	70.9	(28.7)
s18 Current PS Spin	0.9	15.7	(18.6)

Table 28 and Table 29 highlight the unit start effect of both scenarios. In both cases, there is a reduction in coal and combustion turbine starts, and thus a reduction in start costs for these units. As for combined cycle units, there is an increase in starts in the case of the new combined cycle unit in Scenario 17 and a reduction in Scenario 18. In both cases, the reduction in start costs is overwhelmingly due to the reduction in combustion turbine starts.

Table 28. Scenario Effect on Unit Starts Relative to Reference System.

Unit Starts			
Scenario	Coal	CC	CT Gas
s17 CC unit	(57)	26	(638)
s18 Current PS Spin	(4)	(7)	(303)

Table 29. Scenario Effect on Unit Start Costs Relative to Reference System.

Start Costs ($mil 2020)			
Scenario	Coal	CC	CT Gas
s17 CC unit	(1.3)	2.1	(4.1)
s18 Current PS Spin	0.0	(0.4)	(2.4)

Result Commentary

Selected Data

The units selected to highlight the savings for generation costs and start costs, coal, combined cycle, and combustion turbine, were the primary units that presented these savings. Energy storage resources do not largely affect the operation of other units, such as nuclear power plants, the system's integrated gasification combined cycle unit (IGCC) or hydroelectric systems, as these are largely baseload resources. The data presented here is relative to the reference run and is not necessarily indicative of actual system costs of Southern Company's power system.

The General Pattern

The bulk scale energy storage systems evaluated for this study present value to the system in the form of overall generation cost savings. This generation cost savings is represented by savings in the energy generation costs of the system's resources and their start costs. The energy generation costs consist of fuel costs and variable operation and maintenance costs.

As a general rule, bulk scale energy storage reduces expensive generation, in the form of natural gas combustion turbines, and replaces it with lower-cost coal energy, and more efficient combined cycle energy. Energy storage units also reduce the amount of unit starts for many of the system's generating units. This is a result of a reduced need for peaking energy, which is instead provided by the energy storage resources. It is also the result of a reduced need for operating reserves, and the operation of expensive resources to provide these reserves. Energy storage resources either directly provide these reserves, or instead enable already operating units to provide these reserves and themselves provide any necessary peak energy.

Limited Value of Energy Storage

As indicated by the results, additional energy storage resources are of limited value to the Southern Company system as projected in 2020. As discussed previously, this value represents the value of grid-level energy storage providing energy time-of-day shifting, regulation reserve, spinning reserve, and replacement reserve to the system. A consideration of other system services that energy storage resources can provide, such as transmission and distribution capital upgrade deferral, may indicate an increased value for energy storage in the Southern Company system.

Building additional storage to provide time-of-day shifting does not appear to be justifiable under base-case natural gas prices because the difference in price between on-peak and off-peak power is too small.

If we take on-peak to be 10:00 a.m. through 10:00 p.m., and the remaining hours to be off-peak, then in the base case reference run the on-peak average price is less than 10% above the off-peak average price. Adding incremental storage capacity reduces that price differential. With the 800-MW/8-hour pumped storage project added to the reference scenario, the annual average cost difference between on-peak and off-peak power roughly drops in half. With the 3200-MW/8-hour pumped storage project added to the reference system, there is essentially no difference between average on-peak and off-peak power cost.

Likewise, building additional storage to provide operating reserve does not appear to be justifiable with the base-case system of 2020. In the reference run, about 5,700 GWh of synchronized reserve (combined spinning and regulation reserve) is required. With least-cost dispatch, roughly 30,600 GWh of synchronized reserve is available. The Southern Company generation fleet is large enough that economic dispatch usually provides more synchronized reserve than is required.

Of course, not in every hour is there excess synchronized reserve available. In fact, in the reference run, there is a shortage of spinning reserve in 81 hours (about 1% of the hours in the year).[16] The average hourly available response, however, is about 3,960 MW (compared with a required amount of 650 MW).

When there is normally excess synchronized reserve that is a by-product of least-cost dispatch, one would expect that any additional storage would be dispatched infrequently for reserve. The new pumped storage plant in Scenario 1 provides about 5% of the total annual spinning reserve requirement,[17] providing that reserve in about 1,000 hours of the year. While this is a benefit to the system, that benefit does not justify the cost of new plant construction. However, equipping existing hydro plants to provide spinning reserve and regulation is much cheaper than building a new plant, and does appear to be justifiable on a project basis.

As for quick-start (or non-synchronized) reserve, roughly 5,270 GWh is required, while about 75,400 GWh is available. At no time in the reference run is there a shortage of quick-start reserve. Again, the large number of plants on the Southern Company system means that additional quick-start capacity does not add value.

In addition to the factors mentioned above, the Southern Company system has a limited expectation for the deployment of renewable energy resources, with less than a 0.5% deployment by energy planned by 2020. This fact, coupled with low load forecasting errors, means that variability can be handled with a low amount of reserve, which limits the value of additional synchronized reserve. To understand to what extent increased reserve requirements might increase the value of additional storage, this study includes an analysis of a 10% renewable deployment by energy for 2020. Even though reserve requirements greatly increase when 10% of generation is provided from wind, the large amount of synchronized and non-synchronized reserves available means that adding storage to the system provides little value in comparison with capital cost.

An important note is that this analysis covers only the use of energy storage for the bulk grid requirements of energy, regulation reserve, spinning reserve, and quick start reserve. Energy storage for other uses, such as transmission and distribution capacity expansion deferral, has not been evaluated within this project.

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[16] In the model runs for this study, providing the required amount of operating reserve was not a hard constraint. Instead, a penalty price of $1000/MW was imposed for reserve shortfall in each category of operating reserve modeled (spinning reserve, regulating reserve, and quick start reserve). The advantage to this formulation is that a reserve shortfall in a given hour does not cause the entire solution to be infeasible. The disadvantage is that the model will sometimes optimize in ways the actual system operator may not, such as choosing to incur the penalty rather than start a unit to provide the required reserve for only one hour.

[17] In Scenario 1, the new PSH plant provides 260 GWh out of a total spinning reserve provision of 5,700 GWh for the year.

Sensitivity Analysis

Natural Gas Prices

Table 30 depicts the cost savings resulting from each scenario assuming three different natural gas price levels: $5.7, $10, and $15/MMBtu. While most natural gas observers believe that prices will be closer to the $5.7/MMBtu level, it is difficult to forecast prices. Therefore, doing some sensitivities around natural gas pricing gives a picture of a range of possibilities.

Table 30. Natural Gas Pricing at $5.7, $10, and $15/MMBtu.

	Generation Cost (m USD)			Total Generation Cost (m USD)		
Scenario	Base ($5.7/ MMBtu)	$10/ MMBtu Nat Gas	$15/ MMBtu Nat Gas	Base ($5.7/ MMBtu)	$10/ MMBtu Nat Gas	$15/ MMBtu Nat Gas
s1 800/8	(15.2)	(40.8)	(58.5)	(22.6)	(60.9)	(105.3)
s2 800/16	(16.5)	(40.6)	(64.2)	(23.9)	(62.8)	(113.1)
s3 1600/8	(27.7)	(78.6)	(103.6)	(39.8)	(114.7)	(195.3)
s4 3200/8	(38.6)	(124.1)	(166.3)	(57.9)	(173.0)	(309.2)
s5 800/8	(9.6)	(32.6)	(55.0)	(15.7)	(55.2)	(99.5)
s6 800/8	(2.2)	(9.6)	(32.5)	(7.2)	(26.5)	(63.0)
s7 800/16	(1.2)	(8.8)	(29.1)	(6.5)	(25.8)	(59.5)
s8 100/0.25	(0.1)	-	-	(0.3)	-	-
s9 500/4	(7.4)	(18.5)	(39.1)	(11.7)	(28.3)	(53.5)
s10 500/7	(6.4)	(17.8)	(34.0)	(10.2)	(31.6)	(63.5)
s11 100/4	(1.2)	(0.8)	(3.4)	(1.5)	(3.6)	(4.1)
s12 100/1	(1.4)	-	-	(2.6)	-	(1.0)
s13 1600/8 & 100/1	(27.3)	(77.5)	(115.0)	(40.3)	(114.2)	(208.5)
s14 1600/8 & 800/8	(30.0)	(97.0)	(127.1)	(46.4)	(140.7)	(245.1)
s15 3200/8 & 500/4	(41.4)	(132.1)	(180.9)	(62.1)	(181.1)	(327.6)
s16 100/0.25 & 500/4	(8.4)	(22.9)	(44.7)	(12.3)	(31.9)	(60.5)
s17 CC unit	(28.3)	(20.5)	(34.4)	(31.6)	(23.6)	(31.4)
s18 Current PS Spin	(2.0)	(3.2)	(6.7)	(4.8)	(7.5)	(13.1)

Here, the Generation Cost refers to the cost of operating the units, but does not include startup costs. The Total Generation Cost, in contrast, includes startup costs.

To be clear, the Generation Costs and Total Generation Costs of the reference runs increase significantly as the natural gas price increases. In this study, the parameter of interest is the added value of storage, no matter what the price of gas (or any other external variable) is. Table 30 therefore shows the difference in cost between the reference run at a given price of natural gas and the scenario storage run at that same natural gas price.

It is important to note that the numbers reported here assume that the Southern Company generation fleet remains the same, even as the price of natural gas increases. In reality, if natural gas prices were to increase to these levels (and the perception was that they would remain there), then changes to the generation fleet would likely be made. The amount of coal and nuclear generation capacity would probably be increased, as would the amount of wind power contracted for in other parts of the Eastern Interconnect. This probable change in generation mix might not necessarily decrease the value of storage, however. More baseload capacity could act to increase the differential between on-peak and off-peak cost of generation, and may increase the value of spinning and regulating reserve.

Coal Unit 15% Capacity Reduction

Table 31 compares the savings resulting from the different scenarios in two sensitivities: the base case and a 15% reduction in coal unit capacity sensitivity. This 15% reduction could result from less-efficient coal plants becoming unavailable in order to comply with future environmental regulations.

Table 31. System Results for a 15% Reduction in Coal Capacity Relative to the Current Southern Company System.[18]

	Generation Cost ($mil 2020)		Start Costs ($mil 2020)		Total Generation Cost ($mil 2020)	
Scenario	Base System	15% Coal Capacity Reduction	Base System	15% Coal Capacity Reduction	Base System	15% Coal Capacity Reduction
s1 800/8	(15.2)	(17.2)	(7.4)	(9.6)	(22.6)	(26.8)
s2 800/16	(16.5)	(19.7)	(7.4)	(10.0)	(23.9)	(29.7)
s3 1600/8	(27.7)	(32.1)	(12.1)	(18.4)	(39.8)	(50.6)
s4 3200/8	(38.6)	(49.6)	(19.3)	(29.3)	(57.9)	(78.9)
s5 800/8	(9.6)	(12.2)	(6.1)	(9.3)	(15.7)	(21.5)
s6 800/8	(2.2)	(4.8)	(5.0)	(8.4)	(7.2)	(13.1)
s7 800/16	(1.2)	(4.6)	(5.3)	(8.6)	(6.5)	(13.3)
s8 100/0.25	(0.1)	-	(0.2)	(0.1)	(0.3)	(0.2)
s9 500/4	(7.4)	(8.7)	(4.3)	(6.3)	(11.7)	(15.0)
s10 500/7	(6.4)	(8.5)	(3.8)	(6.5)	(10.2)	(15.0)
s11 100/4	(1.2)	(3.1)	(0.3)	(1.4)	(1.5)	(4.5)
s12 100/1	(1.4)	(1.5)	(1.2)	(1.0)	(2.6)	(2.6)
s13 1600/8 & 100/1	(27.3)	(32.6)	(13.0)	(19.0)	(40.3)	(51.5)
s14 1600/8 & 800/8	(30.0)	(39.7)	(16.4)	(23.8)	(46.4)	(63.5)
s15 3200/8 & 500/4	(41.4)	(53.9)	(20.7)	(31.0)	(62.1)	(84.8)
s16 100/0.25 & 500/4	(8.4)	(8.9)	(3.9)	(6.9)	(12.3)	(15.8)
s17 CC unit	(28.3)	(34.4)	(3.3)	(5.4)	(31.6)	(39.8)
s18 Current PS Spin	(2.0)	(1.8)	(2.8)	(1.0)	(4.8)	(2.8)

[18] The scenarios in each sensitivity in the table (base case and 15% coal capacity reduction) are compared with the reference run of that sensitivity.

Based on the results presented here, it is evident that there is an increased value across the board for nearly every scenario relative to the reference run.

The cases of Scenarios 17 and 18 are a bit different, of course, as they are not storage systems. The additional combined cycle gas unit in Scenario 17 is able to provide additional lower cost energy when there is a reduction of coal capacity and therefore reduce peaking unit starts. In Scenario 18, however, the value of the peak-shaving hydroelectric units being able to provide spinning reserve is reduced. With a reduction in coal capacity, there is more need for an energy resource than a reserve resource. Unlike the case of 100% coal capacity, the peak shaving units are unable to facilitate as much increased coal deployment because, simply, the coal units are not present.

Ten Percent (10%) Renewable Penetration

A 10% renewable penetration of wind by energy highlights the effect on the value of energy storage of a significant variable generation deployment. Table 32 presents this effect in the form of a change in generation and start costs relative to a reference system that does not contain additional storage.

Table 32. System Results for a 10% by Energy Deployment of Wind Resources Capacity Relative to the Current Southern Company System.

	Generation Cost ($mil 2020)		Start Costs ($mil 2020)		Total Generation Cost ($mil 2020)	
Scenario	Base System	10% Renewable Penetration	Base System	10% Renewable Penetration	Base System	10% Renewable Penetration
s1 800/8	(15.2)	(20.7)	(7.4)	(5.2)	(22.6)	(25.8)
s2 800/16	(16.5)	(22.1)	(7.4)	(5.7)	(23.9)	(27.8)
s3 1600/8	(27.7)	(35.7)	(12.1)	(11.4)	(39.8)	(47.2)
s4 3200/8	(38.6)	(49.5)	(19.3)	(22.5)	(57.9)	(72.1)
s5 800/8	(9.6)	(15.3)	(6.1)	(6.7)	(15.7)	(22.0)
s6 800/8	(2.2)	(6.0)	(5.0)	(8.2)	(7.2)	(14.2)
s7 800/16	(1.2)	(6.1)	(5.3)	(7.7)	(6.5)	(13.8)
s8 100/0.25	(0.1)	(2.1)	(0.2)	(1.2)	(0.3)	(3.3)
s9 500/4	(7.4)	(12.6)	(4.3)	(4.1)	(11.7)	(16.8)
s10 500/7	(6.4)	(11.6)	(3.8)	(3.7)	(10.2)	(15.3)
s11 100/4	(1.2)	(3.6)	(0.3)	(0.8)	(1.5)	(4.4)
s12 100/1	(1.4)	(2.8)	(1.2)	(1.0)	(2.6)	(3.8)
s13 1600/8 & 100/1	(27.3)	(35.9)	(13.0)	(12.1)	(40.3)	(48.0)
s14 1600/8 & 800/8	(30.0)	(40.6)	(16.4)	(17.3)	(46.4)	(58.0)
s15 3200/8 & 500/4	(41.4)	(53.3)	(20.7)	(23.4)	(62.1)	(76.7)
s16 100/0.25 & 500/4	(8.4)	(14.1)	(3.9)	(3.9)	(12.3)	(18.0)
s17 CC unit	(28.3)	(19.5)	(3.3)	(3.9)	(31.6)	(23.4)
s18 Current PS Spin	(2.0)	(6.3)	(2.8)	(1.4)	(4.8)	(7.7)

The renewable energy deployment has a significant effect on the evaluated value of the energy storage resources. The increase in value is 15% to 25% for the pumped hydro systems, 40% for the CAES system, and around 100% for the cryogen systems. This increase in value largely arises from energy storage resources serving the increased need for regulation services, where otherwise installed thermal generation would serve this need.

APPENDIX D highlights the methodology used to determine these additional reserve requirements.

Wind energy is not priced in this evaluation, and instead assumed as a no-cost resource. Thus any value available for energy storage resources presents itself as replacing some types of thermal generation with other generation (thermal or wind) and reducing energy starts to provide required energy in times of wind generation shortfalls and reserves when required.

In general, the larger energy storage systems enable additional coal generation by enabling a higher level of baseload generation (by charging off-peak and discharging on-peak) and reducing the use of coal units to provide operating reserves. (Instead, these reserves are provided by the energy storage resources.) The storage systems also reduce the need to dispatch combustion turbines for peak power generation. The combination of these factors leads to an overall systems savings.

PROJECT ECONOMICS

Table 33 presents a summary of the total savings in production cost as compared to the reference case for each of the scenarios and sensitivities with an estimate of system capital costs. The 1-year value represents the savings in system production costs relative to a system without an energy storage resource in place. Current system costs are based on manufacturer survey data selected from the *DOE/EPRI Energy Storage Handbook* [5]. The numbers are only for representative purposes as energy storage resource costs vary widely. The basis for the annualized system cost and total system cost estimates is a 40-year lifetime with stack replacements at every 15 years, an 8% cost of capital, and 2.5% annual inflation.[19]

With one exception, storage system values do not approach system costs under the following sensitivities: the base case, a 15% reduction in coal capacity, a 10% wind energy deployment, and a $10/MMBtu natural gas price. That exception to this is that at the $10/MMBtu natural gas price, the CAES facility does appear justifiable. With natural gas prices at $15/MMBtu, on the other hand, a number of the storage scenarios provide savings that justify their cost.

Projects with a business case at the $15/MMBtu natural gas price levels include all of the PSH scenarios, the CAES scenario, the cryogen scenarios, and two of the combination scenarios with a 1600-MW PSH and another storage technology. (In other words, all of the scenarios except the flywheel and battery scenarios, and the combination scenario with a 3200-MW PSH facility). It should be noted here that these valuations would require natural gas to be at $15/MMBtu in 2020, and to remain at that level for the indefinite future. This level of natural gas price is far above current projections, and would be viewed by many as being unrealistic.

It is important to note that the numbers reported here assume that the Southern Company generation fleet remains the same, even as the price of natural gas rises to $15/MMBtu. In reality, if natural gas prices were to increase to these levels (and the perception was that they would remain there), then changes to the generation fleet would likely be made. The amount of coal and nuclear generation capacity would probably be increased, as would the amount of wind power contracted for in other parts of the Eastern Interconnect. This probable change in generation mix might not necessarily decrease the value of storage in this scenario, however. More baseload capacity could act to increase the differential between on-peak and off-peak cost of generation, and may increase the value of spinning and regulating reserve.

Despite the current lack of a business case for bulk scale storage, storage resource costs are rapidly decreasing, and it is possible that in the near future there could be a business case under the more likely sensitivities. With a consideration of other system services storage resources can provide, there may already be a business case. Determining this will require further analysis, but the bulk scale outlook does indicate that there is value for some bulk system services. These results combined with further analysis on other services, such as distribution support, may indicate a current business case for energy storage in the Southern Company system.

[19] Assuming a 15-year stack life for batteries may be optimistic. Since grid-scale battery systems are relatively new, it is difficult to estimate stack life. In addition, we assume that the cost of stack replacement is 60% of the total system capital cost. (The balance of system components, such as the inverter, would presumably not need to be replaced.)

Table 33. One-Year Storage System Value Compared With Estimated System Cost.

[million USD 2020]	1-Year Storage Value					Current System Costs	
Scenario	Base System	15% Coal Offline	10% Renew-ables	$10/ MMBtu NG	$15/ MMBtu NG	1-Year Annualized System Cost Estimate	Total System Cost Estimate
s1 800/8	23	27	26	61	106	80	1,280
s2 800/16	24	30	28	63	114	80	1,280
s3 1600/8	40	51	48	115	196	150	2,560
s4 3200/8	58	79	73	174	310	300	5,120
s5 800/8	16	22	22	56	100	40	640
s6 800/8	8	14	15	27	63	50	880
s7 800/16	7	14	14	26	60	50	880
s8 100/0.25	1	1	4	-	-	10	250
s9 500/4	12	15	17	29	54	70	1,250
s10 500/7	11	15	16	32	64	90	1,560
s11 100/4	2	5	5	4	5	10	250
s12 100/1	3	3	4	-	1	10	120
s13 1600/8 & 100/1	41	52	49	115	209	160	2,680
s14 1600/8 & 800/8	47	64	58	141	246	190	3,200
s15 3200/8 & 500/4	63	85	77	182	328	380	6,370
s16 100/0.25 & 500/4	13	16	19	32	61	90	1,500
s17 CC unit	32	40	24	24	32	30	500
s18 Current PS Spin	5	3	8	8	14	?	?

APPENDIX F contains two additional tables that complement Table 33 by presenting the project valuation data differently.

Based on these results, the authors conclude that with the expected generation fleet and natural gas prices, additional bulk grid electricity storage does not appear to be justifiable on the basis of projected savings. However, if natural gas prices increase significantly from current projections and remain at those elevated levels, then the savings may be adequate to justify several of the projects.

There is a scenario in this analysis that appears to have a good business case at anticipated natural gas price levels: Scenario 18, in which up to 500 MW of peak shaving hydroelectric generation capacity is equipped with the capability to take an AGC signal, and to offer both regulating and spinning reserve capacity. With the expected natural gas price ($5.7/MMBtu in 2020), the annual savings of this scenario is expected to be roughly $5 million. It is logical that better utilizing existing storage would have a stronger project valuation case than would new storage facilities. The authors recommend that this option be explored further.

With the exception of the cryogen storage facility, estimates of the installed cost per kW for each of the technologies were taken from the draft *DOE/EPRI Energy Storage Handbook.* In the case of the battery storage systems, these estimates are a good reflection of how the cost of a storage facility may vary based on the storage capacity specified.[20] For the PSH systems, projected cost based on number of hours of storage was not altered, because this depends on site-specific characteristics. Building a 16-hour reservoir at a well-suited site may cost no more than an 8-hour reservoir in a less-favorable location. Likewise, the authors did not have enough component-specific data to change the price of the cryogen storage system based on storage capacity. Increasing storage capacity on a cryogen system, however, simply involves having more storage tank volume available, which is a small portion of the overall system cost.

In addition, the battery storage scenarios include an uplift in capital cost representing battery stack replacements in years 15 and 30. In calculating this uplift, it was assumed that the cost of replacing the battery stacks is 60% of the overall capital cost of the project. This amount was then discounted using the same inflation rate and required rate of return as applied to the 40-year stream of benefits from each project.

The assumption made here is that the battery stacks would need to be replaced, and that once every 15 years is a reasonable estimate. If the stacks need to be replaced more often, then clearly this increases the project's capital cost. Many factors impact whether or how often battery stacks would need replacement. As experience with grid-scale battery systems progresses, better operating practices will be developed, and more robust battery systems will be manufactured.

[20] This is true because the desired amount of storage played a role in selecting the technology (in the case of the sodium sulfur battery), as well as in determining the cost of a particular technology. Lithium ion, for example, is cheaper when one hour of storage is specified, as opposed to four.

CONCLUSIONS

This study uses hourly production cost modeling to estimate the value of additional grid-scale electric energy storage in the Southern Company system as projected for 2020. The model represents Southern Company's expected generation fleet and load for 2020 and was built primarily from publicly-available system data supplied by Southern Company. This work takes into account the value of energy storage in providing energy time shift, regulation reserve, and spinning reserve to the bulk power system. Distribution-level applications, such as substation capital upgrade deferral or voltage correction on feeders with high photovoltaic penetration, were not examined.

The evaluation involved a number of different energy storage systems of differing sizes, ranging from larger pumped hydroelectric power plants to smaller bulk-scale battery systems. To address possible situational changes, the scenario storage systems were tested against a range of sensitivities: three different natural gas price assumptions, a 15% decrease in coal-fired generation capacity, and a high renewable penetration (10% of total generation from wind energy) scenario.

With the anticipated generation fleet and natural gas prices, additional bulk-scale energy storage does not appear to be justifiable on the basis of projected production cost savings. In the $10/MMBtu natural gas sensitivity, only the CAES project appeared to have a business case. In the $15/MMBtu natural gas sensitivity, nine of the sixteen storage scenarios appeared to have a business case. These two sensitivities specify that the natural gas price remain at these elevated levels essentially for the storage project lifetimes.

While additional storage becomes more attractive in the reduced coal-fired generation sensitivity,[21] system savings from additional storage are still well below levels that we believe would provide economic justification for a project. Likewise, in the high renewable penetration sensitivity, the value of storage is enhanced, but is not enhanced enough to justify the project. While the large wind component requires additional synchronized and non-synchronized reserve, the size and low cost of the Southern Company generation fleet enables it to handle these demands with minimal additional cost.

Building additional storage to provide time-of-day shifting does not provide sufficient value under the base-case natural gas price because the difference in price between on-peak and off-peak power is too small. As the amount of additional storage (capable of time-of-day shifting) increases, the on-peak/off-peak price differential decreases.

Likewise, building additional storage to provide operating reserve is not justifiable in 2020 because of the resource diversity of the power system. In general, the Southern Company generation fleet is large enough that synchronized reserve is far in excess of what is required. However, excess synchronized reserve, as a by-product of least-cost energy dispatch, is not available in each hour. In these hours, additional reserve is valuable.

Because these scenario storage facilities provide both time-of-day shifting and reserve, it is difficult to determine the fraction of value provided by each without doing additional analysis. Such analysis was performed for Scenario 1 (the 800-MW/8-hour PSH facility) and Scenario 4

[21] In this sensitivity, additional capacity was not added to the system to replace the 15% coal-fired generation capacity reduction.

(the 3200-MW/8-hour PSH facility), where the model was run with the scenario storage facility not allowed to provide reserve. Compared with the runs with reserves enabled, the savings was about $0.1 million less in Scenario 1, and $1.2 million less in Scenario 4. We can therefore conclude that the overwhelming majority of the value provided by these two scenario storage projects is from energy time-of-day shifting, and not from the provision of reserve. We believe it is likely in the other storage scenarios involving multi-hour storage that most of the value was also provided by time-of-day shifting service.

Enabling existing peak shaving hydroelectric plants to provide regulation (by enabling some of the plants to take AGC signals) and spinning reserve may be a project with a good business case. The savings resulting from this additional ancillary service capability are estimated to be roughly $5 million per year in the reference case. The study team believes that this is an interesting outcome that calls for more investigation.

Some important caveats are in order. First, the primary focus of this study was to calculate the annual system savings (compared to the reference case) of each scenario. In order to calculate the financial value of each project, we make the assumption that the annual savings calculated are a reasonable estimate of annual savings going forward. Annual savings going forward can differ from those calculated for 2020 mainly for the following reasons: (1) additional variable generation capacity could be installed or contracted for; (2) changes may be made to the conventional generation fleet over time; and (3) fuel prices may vary from those assumed for 2020.

Because they are based on the cost savings calculated for a single year, the study team does not believe that net present value (NPV) calculations in this report are highly accurate estimates of project value. Instead, the study team believes that the NPV calculations here are an indication of a project's potential benefit.

Second, the NPV calculations in this report are also sensitive to assumptions on the discount rate, inflation, and battery stack life and replacement cost (for those projects involving batteries). In this study, we assumed an 8% discount rate and a 2.5% inflation rate for all projects. For those involving batteries, we assumed a 15-year battery stack life, and that the stack replacement cost would be 60% of the initial project capital cost. Lower discount rates (and higher inflation rates) would make the projects seem more attractive than presented here. A shorter battery stack life or higher stack replacement cost would make projects involving batteries less attractive.

Third, this study uses an approximation of Southern Company's reserve specification. The specification of operating reserve is an important factor in how the system is dispatched, and will have an impact on the cost savings yielded by storage projects and new generator additions. Discrepancies in assumed versus actual operational reserve can be a source of error in storage value estimations.

Fourth, the model used for this analysis assumes that there will be no transmission constraints on the bulk power system of Southern Company in 2020. If, in fact, such constraints develop, then additional, properly-placed storage may be able to provide additional benefits by alleviating congestion. Likewise, if there are any areas where transmission capacity upgrades are being considered, storage could act to defer such upgrades. A determination of the level of benefits from transmission upgrade deferral was not part of this study.

Finally, this study does not consider the value of additional storage for distribution-level applications. A distribution value analysis would require additional work to identify possible distribution needs and to estimate the value of serving those needs. Allowing new storage facilities to serve both bulk grid and distribution-level needs may provide for increased benefit streams, and thus make a stronger business case for additional storage.

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APPENDIX A: Model Confidence Building

As discussed in the introduction, the reference model for the 2020 Southern Company system was built with mostly publicly available data on generation units. Southern Company operations provided load estimates for the year 2020.

Using this information, Sandia built the production cost model to represent the Southern Company system for 2020. The initial output from this model was shared with the Southern Company study team to ensure that the generation units generally operate in the model as they do in actual operation.

The Southern Company study team compared the annual output from the Sandia model to what they would expect from actual operations. Where the Southern Company team observed significant deviations in these parameters, it indicated these to Sandia along with possible corrective actions. Many of these issues included must run requirements, some small heat rate corrections and some operational cost fixes. Because of the confidential nature of this data and production costs, specific changes and corrective actions will not be discussed in this report.

APPENDIX B: Storage Modeling

PLEXOS contains a pumped hydro model that allows the user to simulate energy storage resources. It is possible to set maximum and minimum energy levels, round-trip efficiency, generation and pump capacities, and associated costs to model an energy storage system. Additional flexibility is possible with the software's in-built constraint and condition capabilities allowing the user to set operating parameters and limits.

Depending on the scenario, the various storage systems provide energy and reserve service, only energy service or only reserve service. When providing multiple services, the model co-optimizes energy and reserve services over the model horizon (1 week in this study) to determine the least cost dispatch for the entire system.

As discussed previously, a production cost model is unable to dispatch resources to model actual reserve dispatch. Instead, it holds system output in "regulation raise reserve," "raise reserve," and "replacement reserve" categories where they cannot contribute to energy or other reserve services, and therefore it is assumed they will be available to meet reserve requirements. However, in an energy storage system, even with the assumption that is made here of an energy net zero in serving regulation reserve service over a long time frame, there are losses from the inefficiencies of charging and discharging. These losses are not addressed in this study. It is a relatively small system drain. In the end, the results are more optimistic than they would otherwise be.

APPENDIX C: Storage System Operation

The following four graphs highlight the daily hourly average operation of the energy storage units evaluated in the base-case scenario. They are categorized by seasons of the year. These seasons define the system load shape and as a result define the storage generation operating profiles. Positive values indicate generation, negative values indicate charging.

Evidently, storage system operation, across the board, follows load. During off-peak hours, the various storage devices charge. During peak hours, they discharge. This is generally consistent for every storage resource evaluated.

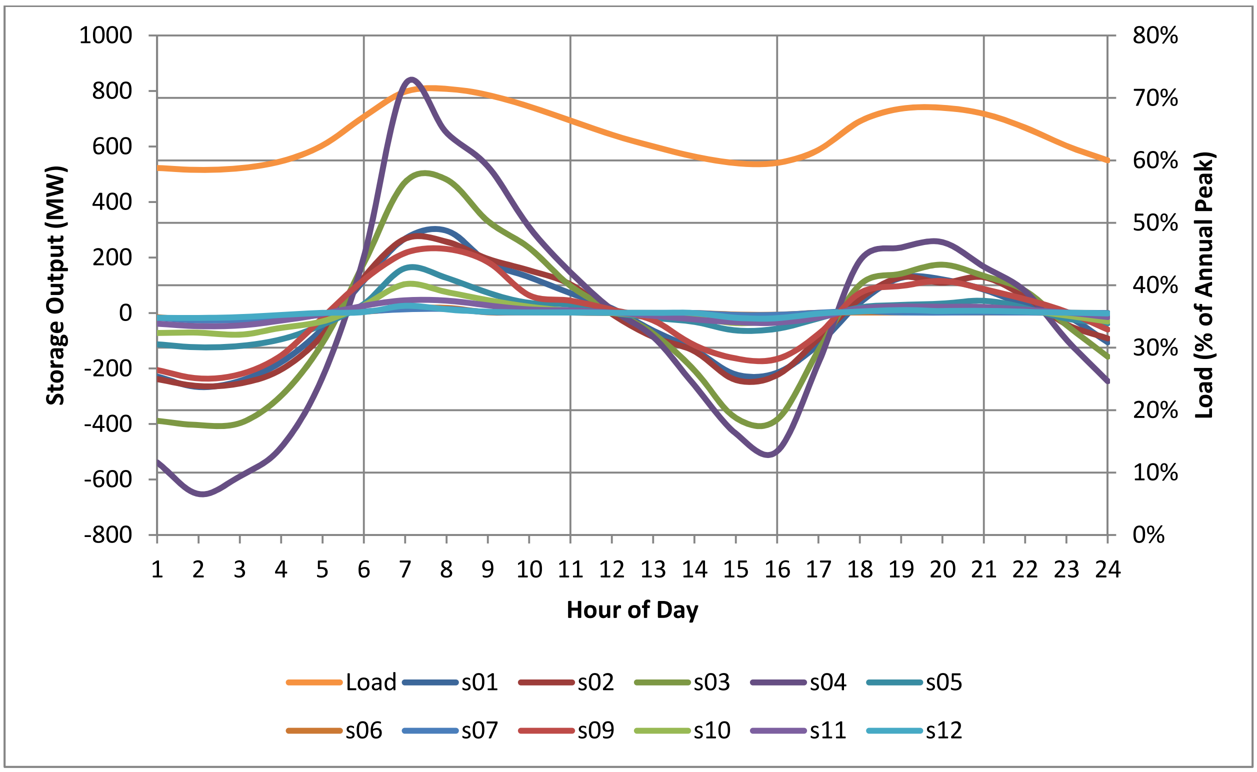

Figure 6. Daily average operation by hour of the scenario storage units from December through February.

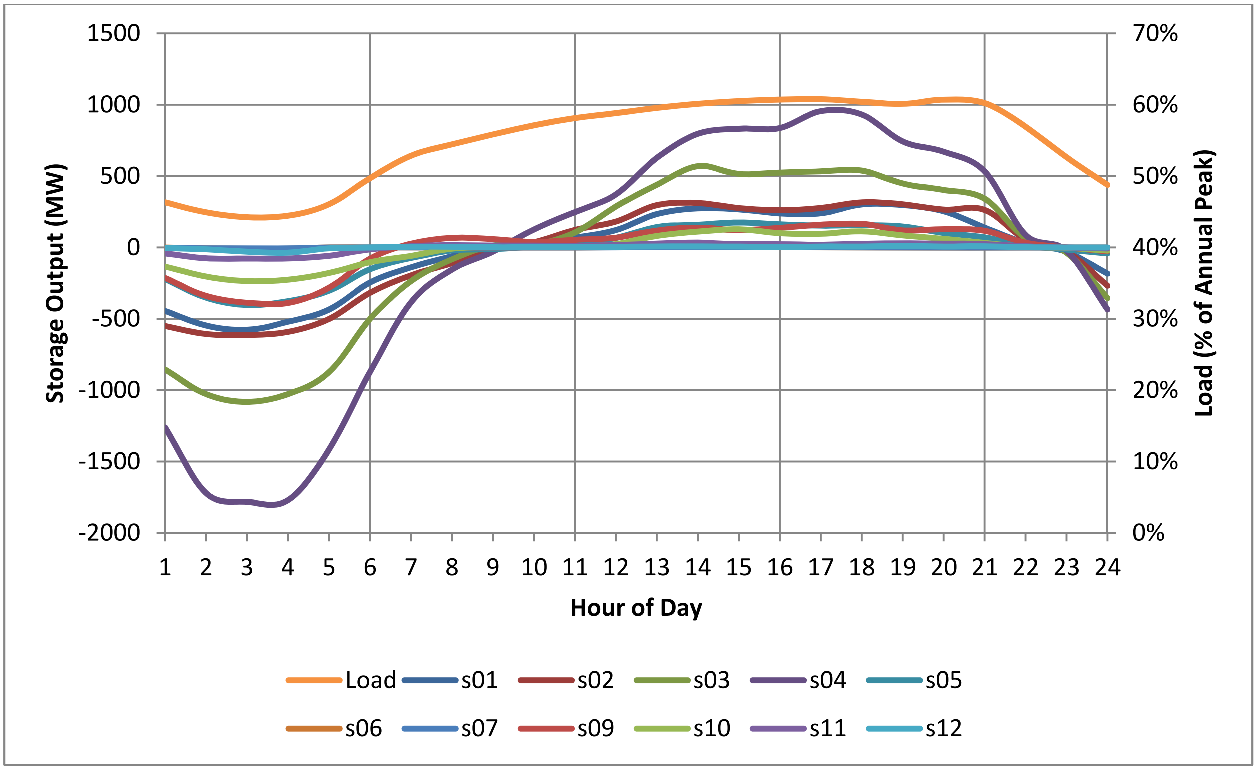

Figure 7. Scenario storage daily average operation from March through May.

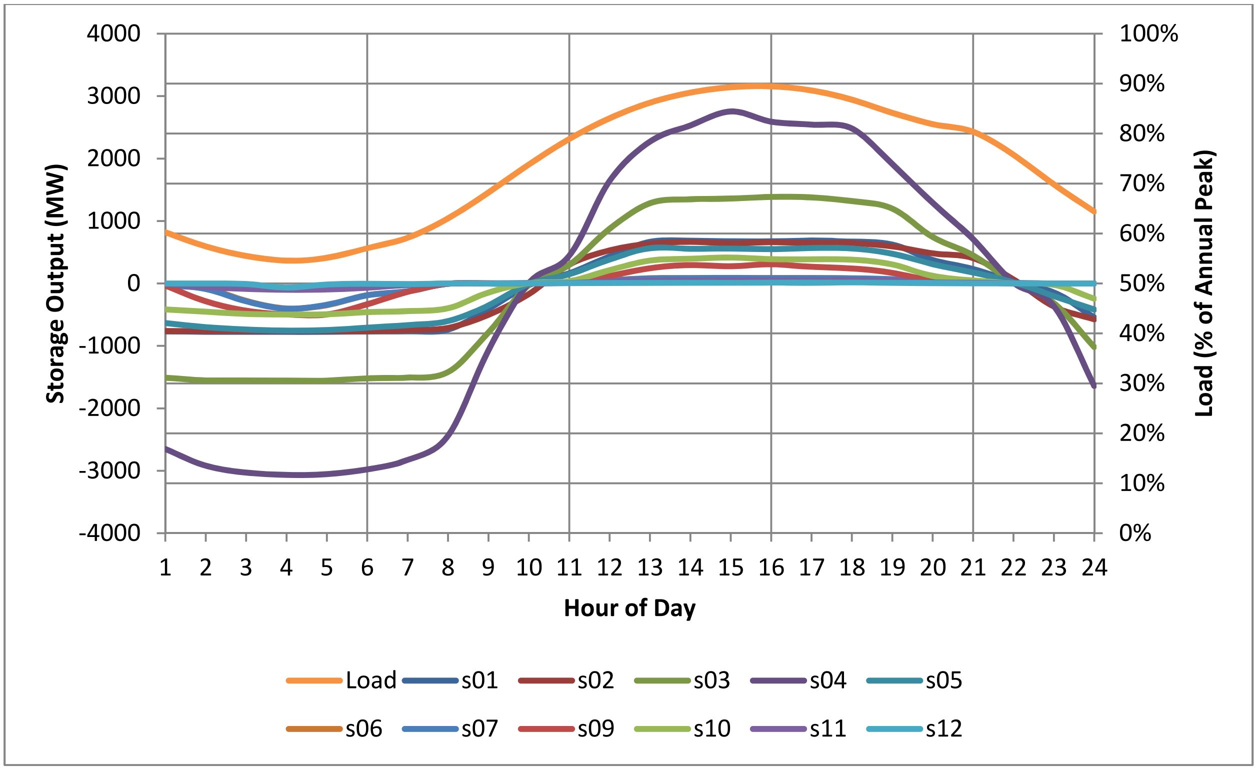

Figure 8. Scenario storage daily average operation from June through August.

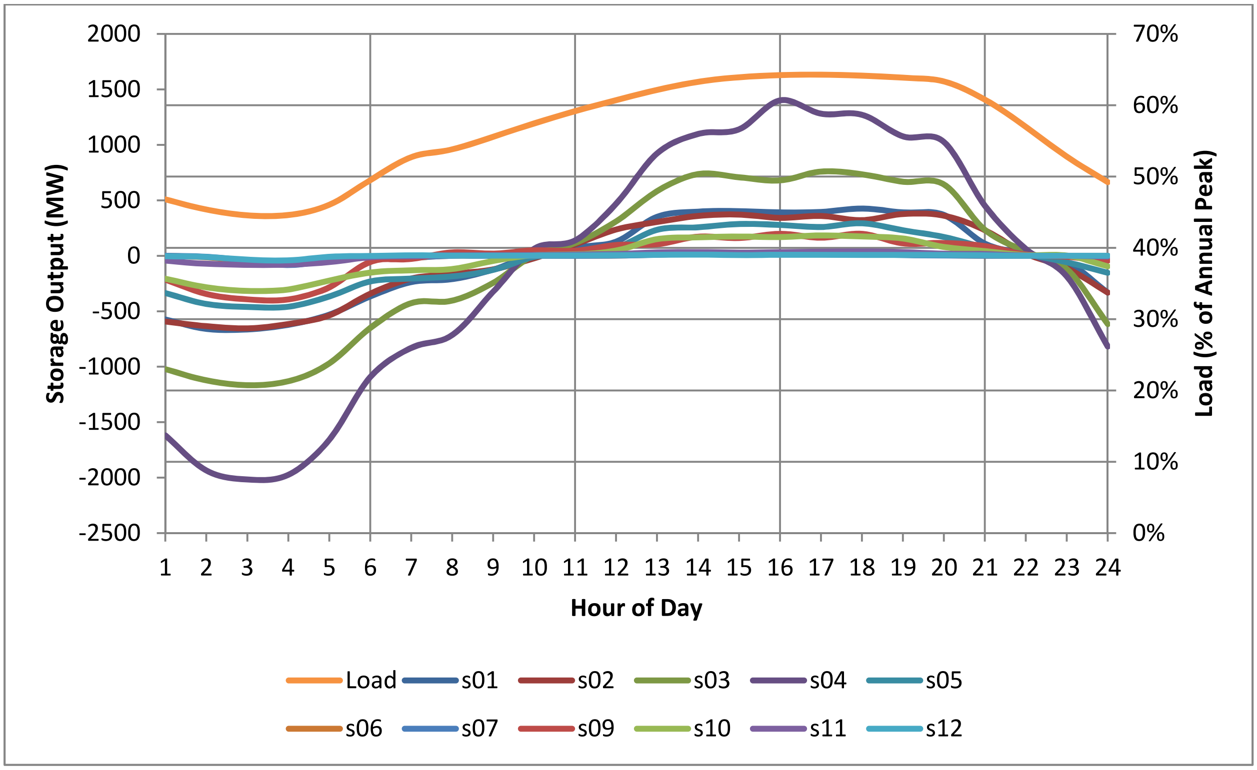

Figure 9. Scenario storage daily average operation from September through November.

APPENDIX D: Wind Data Used for 10% Renewable Sensitivity

Assuming a total generation of 232,100 GWh in 2020, approximately 23,200 GWh of wind-generated power would be needed for a 10% wind renewable penetration sensitivity.

As Southern Company has no plans to produce 10% of total generation from wind by 2020, the study team selected wind data from a number of wind sites in the southern portion of the Great Plains. A total of 11 sites in Oklahoma, Kansas, and the northeastern portion of New Mexico, all of which are in the Eastern Interconnect, were selected. The data for these sites was obtained from the Eastern Wind Dataset.[22]

These sites, along with the installed capacity projected and the resulting amount of generation (based on the wind resource in 2004), are in Table D-1.

Table D-1. Wind Sites Selected for High Renewable Penetration Sensitivity.

Location	State	Capacity (MW)	Generation (GWh)
Whitesboro	OK	100	359
Tucumcari	NM	172	670
Chisholm View	OK	231	811
Mountain View	OK	287	1,070
Fitzhugh	OK	518	1,903
Harper	KS	523	1,747
Overbrook	KS	591	1,976
Union County - A	NM	897	3,396
Union County - B	NM	1,128	4,270
Syracuse	KS	1,143	4,317
Haskell County	KS	1,183	4,561

The generation that would have been provided in 2004 by the specified 11 wind farms, therefore, totals to 25,080 GWh, which is a bit higher than a strict 10% target. Since wind generation fluctuates from year to year, trying to locate those wind sites that would have produced exactly 23,200 GWh in 2004 would not be a meaningful exercise. The study team therefore deemed the 25,100 GWh from the 11 sites to be sufficiently close to a 10% renewable penetration sensitivity for wind.

The wind data was available in 10-minute increments, and was averaged for each hour in order to be compatible with the hourly resolution of the production cost model.

[22] Source: http://www.nrel.gov/electricity/transmission/eastern_wind_dataset.html, accessed January 3, 2013.

APPENDIX E: Reserve Calculation Methodology with 10% Energy from Wind

The approach used here closely follows that used in the Eastern Wind Integration and Transmission Study (EWITS). It is important to note that the standard deviation of the wind forecast error is used in these calculations. It was found in EWITS that the variability of wind generation itself added very little to combined load and wind variability – but that wind forecast errors added a significant reserve requirement.

Both in EWITS and here, the 10-minute-ahead wind forecast error is considered sufficiently short-term to be used to characterize regulation reserve needs.

Overall Operating Reserve Specification

The reserve specification is as follows:

Regulation reserve – There is a component for load, as well as a component for wind. The component of regulation for load is simply 1% of the hourly load. For wind, it is 3 times the standard deviation of the 10-minute-ahead forecast error.

Equation E-1below specifies the total regulation reserve requirement in a given hour.

$$\textit{Regulation requirement (MW)} = 3 * \sqrt{\left(\frac{\textit{Hourly Load}\ (MW) * 1\%}{3}\right)^2 + \sigma_{10-min\ Wind\ Forecast\ Error}{}^2} \quad \textit{(E-1)}$$

Equation E-1finds the combined standard deviation of short-term wind forecast error and load variations by summing the squares of the standard deviation of short-term load variability and short-term wind forecast error variability, and taking the square root of this result.[23]

To calculate the short-term load standard deviation, we assume that the regulation component for load alone (1% of load) is 3 times the standard deviation of load variability on a short-term time scale.[24] Therefore, the Hourly Load * 1% is divided by 3 to obtain one standard deviation of the short-term load variability.

The combined standard deviation of short-term wind forecast error and load variations is then multiplied by 3 to calculate the regulation requirement in each hour. This results in three standard deviations, which should be sufficient to deal with 99.7% of short-term variability.

Spinning reserve – Equals contingency spinning reserve plus a component for wind. For contingency, we assume a fixed 650 MW in each hour. For wind, we use one standard deviation of the hour-ahead forecast error.

[23] The standard deviation of the sum of two random variables is found by summing of the squares of the standard deviations of the two variables, adding twice the covariance, and then taking the square root of that result. In this case, we assume the covariance to be zero, so the term for the covariance is zero.

[24] In a normal distribution, three times the standard deviation covers 99.7% of all samples. Since 1% of hourly load for regulation is an approximation of what utilities generally specify, and since that level of regulation works in practice, it is reasonable to say that it must be enough to cover almost all of the short-term load variation – which is accomplished by specifying three standard deviations of short-term load variation.

Quick start (non-synchronized) **reserve** – Equals contingency quick start reserve plus a component for wind. For contingency, we use a fixed 600 MW. For wind, we use two standard deviations of the hour-ahead forecast error.

The reason one standard deviation of the hour-ahead forecast error is used for spinning reserve and two standard deviations is used for quick start reserve is that a total of three standard deviations are needed to ensure 99.7% of the hour-ahead wind forecast errors are covered – but not all of this needs to be in spinning reserve. The Eastern Wind Study team argues that one standard deviation in spinning reserve is enough; apparently, the wind output tends to change at a rate that makes it possible to use quick start reserves to cover the shortfall for those instances when forecast error is large.

Calculating Standard Deviation of Wind Forecast Error

Here we were not simply interested in calculating the overall standard deviation for wind forecast error – we were interested in the standard deviation of the forecast error as a function of wind output. This is because in EWITS it was found that wind forecast accuracy (which is characterized by the forecast error standard deviation) depends on the level of wind generation when making that forecast.

A year's worth of 10-minute wind data was used. For the 10-minute-ahead forecast, the average of the previous six 10-minute generation levels was used. For the hour-ahead forecast, the average output of the current hour (a persistence forecast) was used. The forecast error was calculated by subtracting the actual output from the forecast output.

In order to find the standard forecast error deviations at different levels of output, the data pairs (generation level and forecast error at that generation level) were sorted according to generation level, and the standard deviation of the errors was calculated for different ranges of generation. In this analysis, 13 blocks of data (spanning 500 MW of generation each) were used. For example, the actual production and forecast error data pairs for actual output levels ranging from 0 to 499 MW were placed into one block, and a mean and standard deviation for the forecast error was calculated for this set of data.

The results of the forecast error standard deviation for the hour-ahead forecasts are illustrated in Figure E-1.

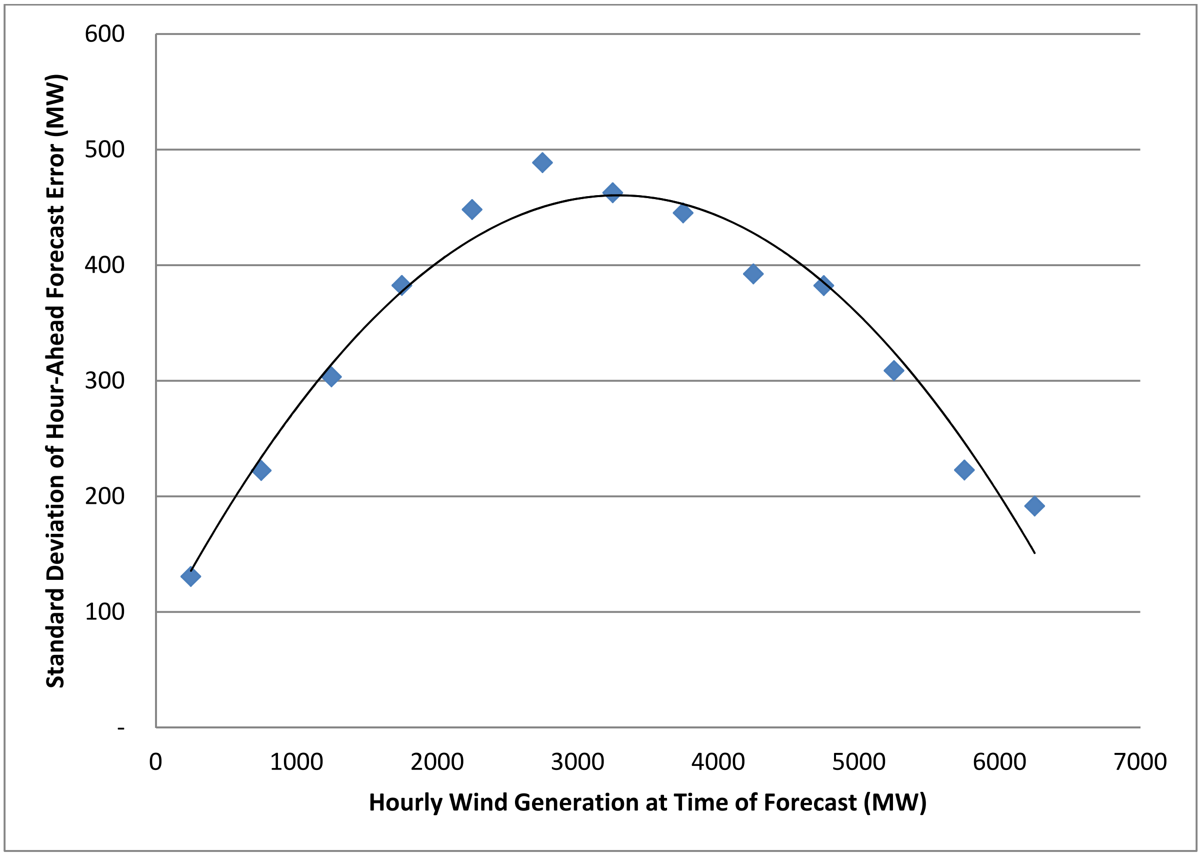

Figure E-1. Spinning Reserve Required Because of Hour-Ahead Wind Forecast Error.

As in the EWITS report, we see that the forecast error standard deviation is smallest at low and high levels of wind generation, and largest at mid-range levels of wind generation. The explanation given in the EWITS report is that at high levels of wind generation many turbines are experiencing wind levels greater than that needed for maximum output. In these conditions, an unexpected reduction (or increase) in wind speed does not translate into a proportionate change in power output. At low levels of power output, there is little wind; hence, large reductions in generation are not possible. At mid-range levels of output, however, large changes in wind speed (either up or down) are possible, and changes in wind speed do translate into changes in power output.

The next step is to derive an equation that describes the standard deviation of the wind forecast error as a function of hourly wind generation at the time the forecast was made. This is needed in order to specify what level of reserves is needed for each hour in the production cost model run. A second-order polynomial trendline through the 13standard deviation points is shown in Figure E-1. While this line is the best second-order polynomial fit for the data, it does not capture what appears to be the area of highest standard deviation. Therefore, we derived the polynomial from the following graph in Figure E-2.

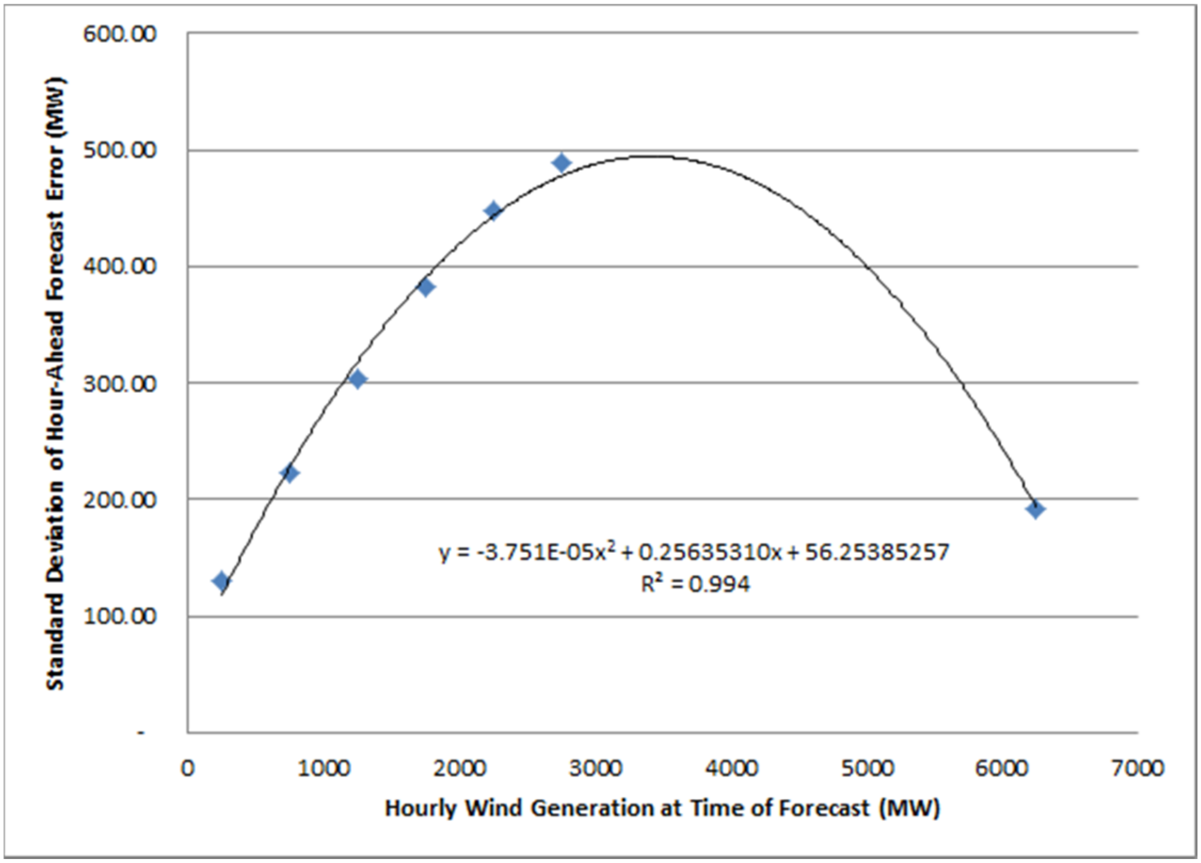

Figure E-2. Modified Graph of Spinning Reserve Required Because of Hour-Ahead Wind Forecast Error.

The second-order polynomial **y = -3.751E-05 * x^2 + 0.2563531 * x + 56.25** was used to calculate the spinning reserve required because of the hour-ahead forecast error in the production cost modeling.[25] In this equation, x is the actual hourly wind generation at the time of the forecast, and y is the calculated standard deviation of the hour-ahead forecast error in the production cost modeling.

[25] The spinning reserve specification because of the hour-ahead wind forecast error is equal to one standard deviation of the forecast error.

An identical process was used to calculate the standard deviation of the 10-minute-ahead wind forecast errors (see Figure E-3).

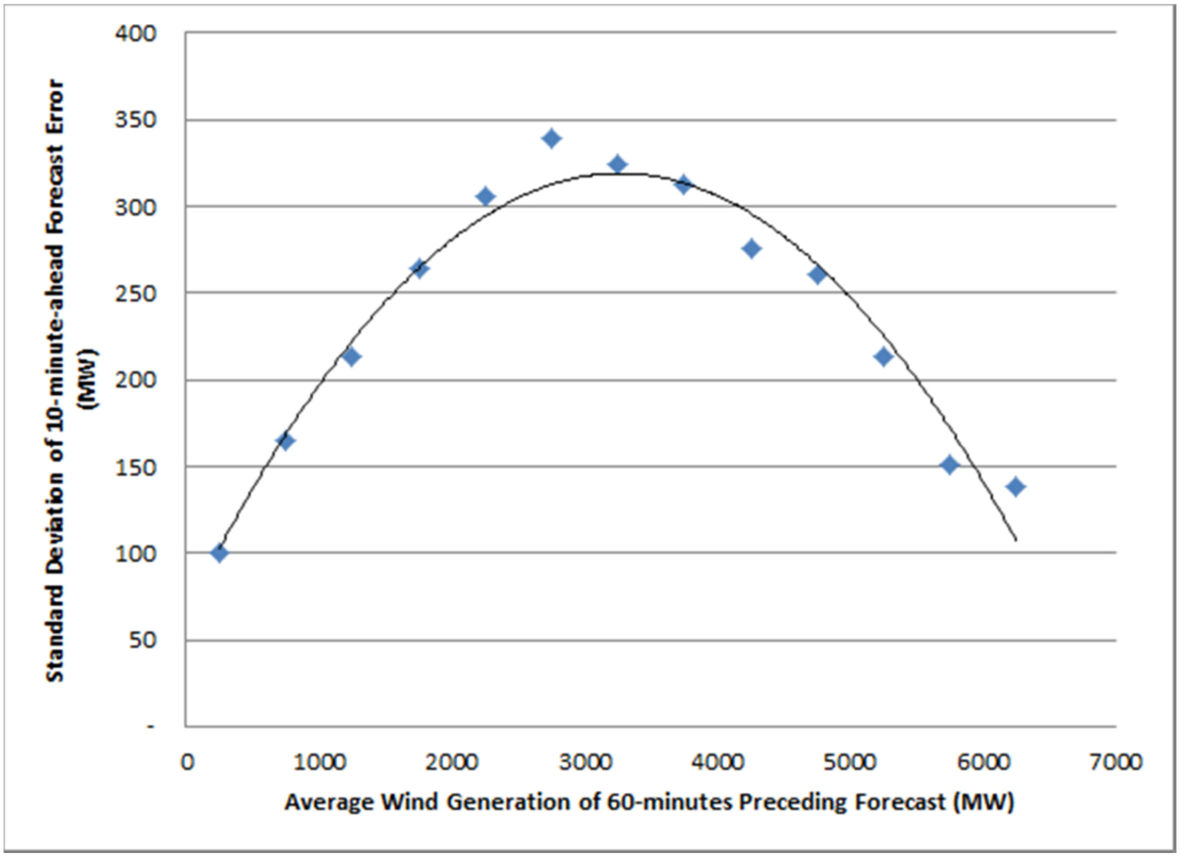

Figure E-3. Standard Deviation of 10-Minute-Ahead Wind Forecast Error.

While the standard deviation of the 10-minute-ahead forecast error is lower than that for the hour-ahead forecast error, the shape of the trendline is similar.

Again, in order to capture more of the peak, we created a modified graph to derive the equation that relates the wind generation of the previous 60-minute period with the 10-minute-ahead forecast error standard deviation. That graph is illustrated in Figure E-4.

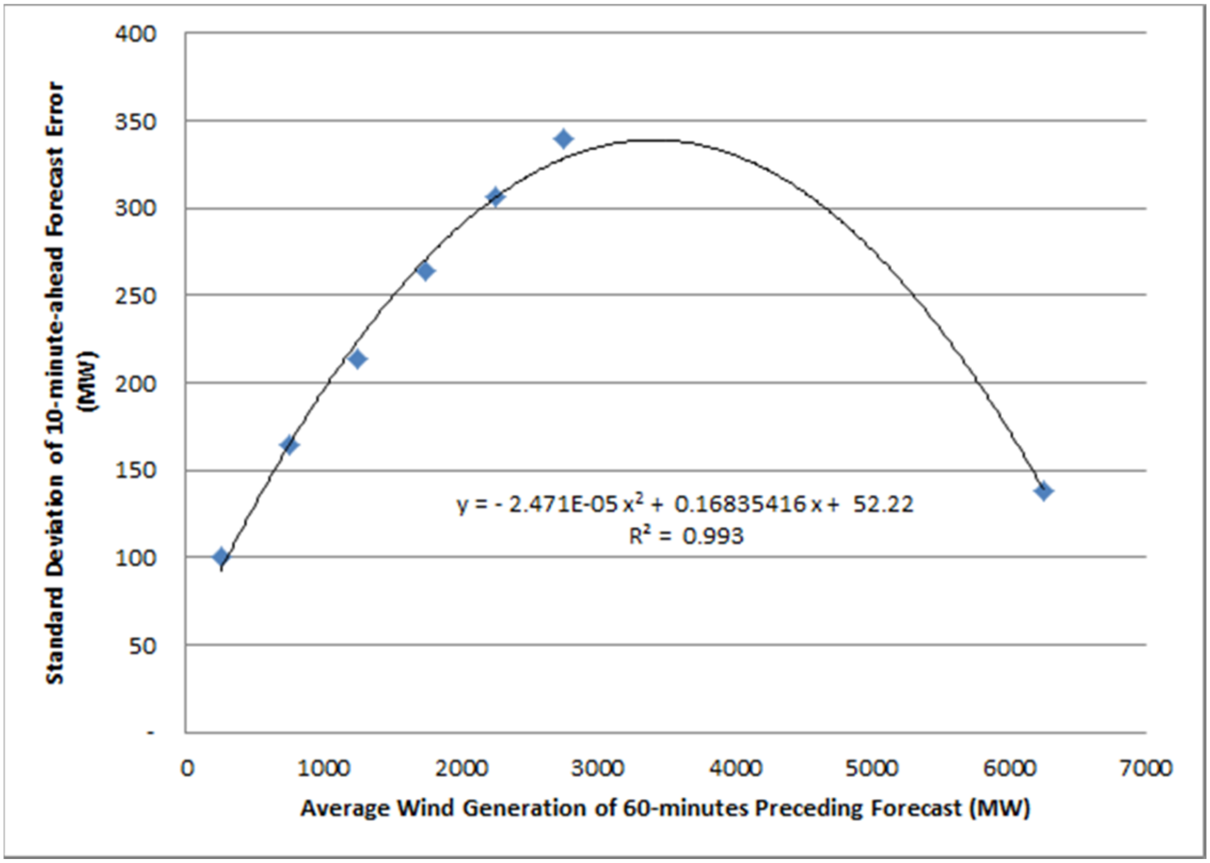

Figure E-4. Modified Graph of Standard Deviation of 10-Minute-Ahead Wind Forecast Error.

The second-order polynomial **$y = -2.471E\text{-}05 * x^2 + 0.16835416 * x + 52.22$** was used to calculate the standard deviation of 10-minute-ahead forecast error.

Calculating Regulation, Spinning Reserve, and Quick Start Reserve

Now that we have discussed how the standard deviation of the wind forecast error is used for calculating reserve, and how that standard deviation was determined, we will demonstrate the results of these calculations.

Table E-1 illustrates the regulating reserves calculation for the first 10 hours of 2020. The regulation for load, as discussed, is simply 1% of the hourly load. The standard deviation of the 10-minute-ahead wind forecast error was calculated by the second-order polynomial derived above (y = -2.471E-05 * x2 + 0.16835416 * x + 52.22). The total regulating reserve requirement was calculated by using these two columns as an input to Equation E-1.

Table E-1. Regulation Reserve Sample Calculation.

Hour	2020 Hourly Load	Hourly Wind	Regulation for Load	Std Deviation 10-Min Forecast Error Wind	Total Regulation
1	20,002	3,704	200	337	1,030
2	19,649	4,460	196	312	955
3	19,505	5,084	195	269	832
4	19,461	5,297	195	251	777
5	19,770	5,338	198	247	766
6	20,481	5,503	205	230	721
7	21,151	5,569	212	223	703
8	21,613	5,399	216	241	754
9	22,678	4,921	227	282	877
10	23,628	4,877	236	286	889

As can be seen in Table E-1, the total regulation reserve required is much less than what would be obtained by summing the standard deviation for load variation and the standard deviation for 10-minute-ahead wind forecast error, and multiplying by 3. In fact, the total regulation reserve is close to taking the 10-minute-ahead wind forecast error alone and multiplying by 3. This smaller-than-expected regulation requirement is a result of the assumption that load variation (at a short time scale) and 10-minute-ahead wind forecast error are completely uncorrelated.

Table E-2 illustrates the spinning reserve calculation as made for this study. The standard deviation for the hour-ahead wind forecast error is calculated by plugging the actual wind output of the previous hour (for the variable x) into the formula previously discussed: **$y = -3.751E\text{-}05 * x^2 + 0.2563531 * x + 56.25$**.

Table E-2. Spinning Reserve Sample Calculation.

Hour	2020 Hourly Load	Hourly Wind	Std Deviation next hr FE Wind	Total Spinning Reserve	Change in Wind Generation	Adjust-ment	Adjusted Spinning Reserve
1	20,002	3,704	491	1,141	-	-	1,141
2	19,649	4,460	491	1,141	757	-	1,141
3	19,505	5,084	453	1,103	624	-	1,103
4	19,461	5,297	390	1,040	213	-	1,040
5	19,770	5,338	362	1,012	41	-	1,012
6	20,481	5,503	356	1,006	165	-	1,006
7	21,151	5,569	331	981	66	-	981
8	21,613	5,399	320	970	(171)	(171)	800
9	22,678	4,921	347	997	(478)	(347)	650
10	23,628	4,877	409	1,059	(44)	(44)	1,016

The next column to the right in Table E-2, the total spinning reserve, is calculated simply by adding 650 to the previous column. This 650 MW represents the spinning reserve component of contingency reserve, which in this study was the assumed requirement for each hour. This total spinning reserve number is not the spinning reserve requirement used in the model.

An additional step was taken that adjusts the spinning reserve component for wind in those hours that wind is lower than forecast. In reality, in those hours wind generation is below forecasted levels the spinning reserve would be deployed to cover the shortfall. Because the production cost model is hourly, we reduce the wind component of the spinning reserve to reflect that this amount has been deployed (otherwise, we would be both dispatching to cover the shortfall and holding the full amount of the spinning reserves for wind – which would be, in effect, double-counting).

The columns “Change in Wind Generation” and “Adjustment” in Table E-2 demonstrate this calculation. The “Change in Wind Generation” column shows the change in wind generation from the previous hour, and the “Adjustment” column shows how much the number calculated in the “Total Spinning Reserve” column needs to be adjusted to yield the actual spinning reserve requirement (termed the “Adjusted Spinning Reserve” here). As can be seen, when the wind generation increases (as compared to the previous hour), no adjustment is made. When it decreases, an adjustment is made in spinning reserves, but only up to the amount that had been reserved for the wind component of the spinning reserves. In no case is the spinning reserve specification allowed to fall below the contingency reserve amount of 650 MW.

Finally, Table E-3 illustrates the calculation for the total amount of quick start reserve required over the same 10 hours. Here, the amount of quick start reserve for wind is twice the standard deviation for the next-hour wind forecast error. To calculate the total quick start reserve required in each hour, we simply add 600 MW to the amount of quick start reserve for wind. This 600 MW is the assumed amount of quick start reserve for contingency that Southern Company must carry in each hour.

Table E-3. Quick Start Reserve Sample Calculation.

Hour	2020 Hourly Load	Hourly Wind	Std Deviation Next-hr FE Wind	Quick Start for Wind	Total Quick Start
1	20,002	3,704	491	982	1,582
2	19,649	4,460	491	982	1,582
3	19,505	5,084	453	907	1,507
4	19,461	5,297	390	780	1,380
5	19,770	5,338	362	723	1,323
6	20,481	5,503	356	712	1,312
7	21,151	5,569	331	662	1,262
8	21,613	5,399	320	641	1,241
9	22,678	4,921	347	694	1,294
10	23,628	4,877	409	819	1,419

An additional point is that under this methodology the regulation and the spinning reserve must be mutually-exclusive. This is different from Southern Company's existing reserve specification, which we understand allows regulation reserve to contribute towards spinning reserve.

APPENDIX F: Additional Economic Valuation Tables

Taking the one-year cost savings estimates presented in Table 33 and projecting the same savings level each year for forty years, we can calculate the total capital cost supported by this stream of savings. The results of these calculations are presented in Table F-1.

Table F-1. Forty-Year Estimates for Total Supported Capital Costs Storage Compared With Estimated Capital Cost of the Storage System

[million USD 2020]	Total Supported Capital Cost (40-Year Estimate)					Estimated Capital Cost[26]
Scenario	Base System	15% Coal Offline	10% Renew-ables	$10/ MMBtu Nat Gas	$15/ MMBtu Nat Gas	Estimated System Capital Cost
s1 800/8	390	460	440	1,050	1,810	1,280
s2 800/16	410	510	480	1,080	1,950	1,280
s3 1600/8	690	870	810	1,970	3,360	2,560
s4 3200/8	1,000	1,360	1,240	2,980	5,320	5,120
s5 800/8	270	370	380	950	1,710	640
s6 800/8	120	230	240	-	1,080	880
s7 800/16	110	230	240	440	1,020	880
s8 100/0.25	-	-	60	-	-	250
s9 500/4	200	260	290	490	920	1,250
s10 500/7	180	260	260	540	1,090	1,560
s11 100/4	30	80	80	60	70	250
s12 100/1	40	40	70	-	20	120
s13 1600/8 & 100/1	690	890	830	1,970	3,590	2,680
s14 1600/8 & 800/8	800	1,090	1,000	2,420	4,220	3,200
s15 3200/8 & 500/4	1,070	1,460	1,320	3,120	5,640	6,370
s16 100/0.25 & 500/4	210	270	310	550	1,040	1,500
s17 CC unit	540	680	400	410	540	500
s18 Current PS Spin	80	50	130	130	230	-

[26] These numbers were calculated by multiplying the estimated installed cost per kW by the plant nameplate capacity. The battery storage scenarios include an uplift representing battery stack replacements in years 15 and 30. Except for the cryogen storage plant, all installed cost estimates are from the draft *Energy Storage Handbook*.

The total supported capital cost takes the one-year cost savings, assumes the value of savings is the same for each year, and discounts this stream of savings back to 2020 (the system study year). To obtain the present value of the stream of cash flows (in 2020), an 8% discount rate and a 2.5% inflation rate are applied.

It is true that the one-year cost savings value is unlikely to remain the same for the entire forty year horizon. There are a number of factors which can either increase or decrease the amount of savings resulting from the addition of the storage facility. These factors include (but are not limited to) increased levels of variable generation, increased load variability, changes in fuel prices, and changes in generation fleet composition. However, it is very difficult to predict these factors. In absence of such a prediction, we maintain that calculating the likely cost savings for a given year in a rigorous way, and extrapolating this level of savings into the future, provides important insight into whether a project is likely to be justifiable on the basis of system savings.

Finally, Table F-2 presents the numbers in yet another format, looking at costs per specific power output, again based on a 40-year project horizon. In the base case sensitivity (which assumes a fixed natural gas price of $5.70/MMBtu on a real dollar basis for the 40-year project horizon), pumped hydroelectric systems need to be in the range of $500/kW in order to be justifiable on the basis of system savings (current costs are around $1,600 to $1,900/kW). Battery systems need to be in a similar range to be justifiable in the base sensitivity case (they are currently around the $1,500 to $4,000/kW range depending on the technology). [5] As shown in the table, higher natural gas prices increase the level of justifiable costs.

Table F-2. Supported Capital Costs Per Unit Power Output Based on a 40-Year Estimate for Total Supported Storage System Capital Costs (40-Year System Value) for Each Scenario and Sensitivity and an Estimate of Current System Capital Costs.[27]

[$2020/kW]	Supported Capital Cost					System Capital Cost Estimates	
Scenario	Base System	15% Coal Offline	10% Renew-ables	$10/ MMBtu Nat Gas	$15/ MMBtu Nat Gas	Low	High
s1 800/8	490	580	560	1,310	2,270	1,600	1,900
s2 800/16	510	640	600	1,350	2,430	1,600	1,900
s3 1600/8	430	540	510	1,230	2,100	1,600	1,900
s4 3200/8	310	420	390	930	1,660	1,600	1,900
s5 800/8	340	460	470	1,190	2,140	700	2,100
s6 800/8	160	280	310	-	1,350	1,100	1,500
s7 800/16	140	290	300	550	1,280	1,100	1,500
s8 100/0.25	50	30	570	-	-	2,000	3,000
s9 500/4	400	510	580	970	1,840	2,400	5,000
s10 500/7	350	520	530	1,090	2,190	3,000	3,500
s11 100/4	250	780	750	630	710	2,400	5,000
s12 100/1	440	440	660	-	170	1,400	3,000
s13 1600/8 & 100/1	410	520	490	1,160	2,110	1,600	
s14 1600/8 & 800/8	330	460	420	1,010	1,760	1,300	
s15 3200/8 & 500/4	290	390	360	840	1,520	1,800	
s16 100/0.25 & 500/4	350	450	520	920	1,730	2,800	
s17 CC unit	650	810	480	480	640	600	

[27] Manufacturer survey estimates from *DOE/EPRI Energy Storage Handbook.*

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