# A Framework for Determining The Costs and Benefits of Renewable Resources in Georgia

**Revised: 1/17/19**

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## SECTION 1 – EXECUTIVE SUMMARY

### Introduction

When considering any generation technology, including renewable resources, it is crucial that all of the appropriate costs and benefits of such technology be determined and allocated in a way that ensures equitable treatment and continued reliability of the system. The application of these costs and benefits becomes more important as the number of intermittent renewable resources being deployed to serve customers continues to grow. Additionally, numerous “Value of Solar” (“VOS”) studies have been performed in the industry in recent years suggesting various costs and benefits associated with solar generation. Over the same period, there has been increased activity by the solar industry at the various state regulatory agencies of Southern Company, some of which suggested the need for a VOS determination within those jurisdictions. It was during this period that Southern Company established a framework for determining the costs and benefits of renewable resources on the Southern Company electric system (“Framework” or “RCB Framework”), originally filed publicly in Georgia Power Company’s (“Georgia Power”) 2016 Integrated Resources Plan (“IRP”). The purpose of this document is to describe that Framework and how it will be used in determining the appropriate costs and benefits of renewable resources on the Southern Company electric system, specifically related to Georgia Power. Georgia Power has revised the Framework from the version filed in May 2017 with the Georgia Public Service Commission (“GPSC” or “Commission”) to consolidate some items for simplification, to add clarity to descriptions and explanations in other areas, and to clean up formatting and labeling for consistency. Georgia Power does not propose any additional components be considered for inclusion in the Framework beyond what is currently approved in the Joint Recommendation filed December 2016; however, one component is being moved from placeholder status to exclude status.

### Components Included in the Cost-Benefit Analysis

Through rigorous review of various industry studies and reports related to the VOS and comparing them to Southern Company’s current generation evaluation methodologies, in conjunction with Southern Company’s experience with actual renewable resources installed on the Southern Company system, Southern Company identified components that should be considered in calculating the costs and benefits of renewable resources on the Southern Company electric system. Among the studies reviewed were the following: “Minnesota Value of Solar: Methodology” (April 2014); “2014 Value of Solar at Austin Energy” (October 2013); “The Benefits and Cost of Solar Distributed Generation for Arizona Public Service” (May 2013); “A Review of Solar PV Benefits & Cost Studies” (April 2013); “The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania” (November 2012); “The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources” (February 2014); and “Maine Distributed Solar Valuation Study” (March 2015). The Company continues to monitor industry studies and reports, market conditions, and policy changes in other jurisdictions related to the VOS to stay abreast of current trends in this field.

For solar resources, Southern Company recognizes two primary categories of solar to differentiate the type of solar generation being evaluated. Those categories are as follows:

1. **Utility Scale ("US"):** Central station solar generation facilities that are interconnected at the transmission level ("US-T") or at the distribution level on a dedicated distribution feeder ("US-D").
2. **Distributed Generation ("DG"):** Either greenfield central station solar generation facilities that are interconnected at the distribution level on an existing (non-dedicated) distribution feeder ("DG-G"); or solar generation facilities at or adjacent to a customer's site, where the solar generation is metered separately from the load ("DG-M"); or, in cases where only a bi-directional meter exists, the solar generation is in excess of customer load and sold to the host utility in accordance with applicable laws and tariff requirements ("Behind-the-Meter" or "DG-BTM").

Appendix A contains representative single line diagrams for each of the above categories.

Table 1 shows the list of cost-benefit components included in the RCB Framework, or in placeholder status, and whether each component is a cost or a benefit. Each of these components is discussed further in Section 3.

**Table 1: In Scope Renewable Cost Benefit Components**

| Component | Utility Scale | Distributed Generation | Component Status |
|---|---|---|---|
| **Avoided Energy Costs (1)** | Benefit | Benefit | Included |
| **Deferred Generation Capacity Costs (2)** | Benefit | Benefit | Included |
| **Reduced Transmission Losses (Energy Related)** | Benefit | Benefit | Included |
| **Reduced Transmission Losses (Capacity Related)** | (3) | Benefit | Included |
| **Deferred Transmission Investment** | (3) | Benefit | Included |
| **Reduced Distribution Losses (Energy Related)** | N/A | (4) | Included |
| **Distribution Operations Costs** | N/A | Cost | Placeholder |
| **Generation Remix** | Cost or Benefit | Cost or Benefit | Included |
| **Ancillary Services – Reactive Supply and Voltage Control** | N/A | Cost | Placeholder |
| **Ancillary Services – Regulation** | Cost | Cost | Included |
| **Support Capacity (Flexible Reserves)** | Cost | Cost | Included (5) |
| **Bottom Out Costs** | Cost | Cost | Placeholder |
| **Long-Term Service Agreement Costs** | Cost | Cost | Placeholder |
| **Program and Administration Costs** | (See note 6) | | Placeholder |

Notes:

(1) Includes Avoided Fuel and Purchased Power Costs, Avoided Generation Variable Operation and Maintenance Costs, Avoided Water Consumption Costs, and Avoided Environmental Compliance Costs.
(2) Includes Deferred Reserve Capacity Costs and Generation Fixed Operation and Maintenance Costs.
(3) Determined on a case by case basis.
(4) Should be determined on a case by case basis for DG-G but will be presumed as a benefit in the aggregate. Represents a benefit for DG-M and DG-BTM.
(5) Support Capacity – Ramping is currently in placeholder status.
(6) Determined on an Operating Company specific basis.

**Limitations on the Scope of Analysis**

When considering the costs and benefits of renewable resources (or any other technology), there are many possible views. Georgia Power is a vertically integrated, state-regulated utility, and as such, there are certain limitations regarding what can (and cannot) properly be considered in such analyses. This Framework is based on existing legal and regulatory requirements applicable to Georgia Power as well as industry standards. The overall value of solar generation to Georgia Power is dependent upon current rules, regulations, standards, and market structure, and per planning practice, any potential future changes to these conditions are not considered in this analysis. Similarly, this Framework considers technology and supporting infrastructure as they exist presently. As the balance of resources on the system evolves with increasing penetrations of renewable resources, intra-hour modeling may become necessary to fully capture the impacts associated with new technologies. However, hourly modeling remains sufficient within the current environment. Although future technological developments may well have an impact on the costs and benefits of renewable generation, until such developments transpire, a practical analysis can only account for the current state of technology and infrastructure.

## SECTION 2 – BACKGROUND AND PURPOSE

The cost of renewable resources continues to drop significantly, and there have been a number of developments related to renewable resources in the electric industry in general, and in the Southeast in particular, that impact Georgia Power. Renewable resources will remain an integral part of the generation mix in the electric industry. As such, the continued evaluation of the costs and benefits of grid-connected renewable resources is essential as the penetration of renewable resources grows.

The state of Georgia continues to be a national leader in the development of renewable resources. Georgia Power is a proponent of adding cost-effective renewable resources that benefit its customers. A cornerstone of Southern Company's renewable development strategy is the commitment to calculate, analyze, and accurately apply the costs and benefits of renewable generation in order to maximize the benefits these resources provide. The Georgia renewable energy market continues to flourish, without a mandate, and the use of the Commission-approved RCB Framework ensures all stakeholders a fair recognition of the impacts these resources have.

Driven by market conditions and regulatory requirements, Southern Company worked to establish a methodology to appropriately reflect the costs and benefits of renewable resources across the Southern Company electric system, and introduced the RCB Framework in Georgia Power's 2016 IRP. Pursuant to the Stipulation approved by the GPSC in Georgia Power's 2016 IRP in Docket No. 40161, the Company worked collaboratively with Commission Staff to refine and clarify the application of the RCB Framework by Georgia Power. On December 2, 2016, Georgia Power and Commission Staff filed a Joint Recommendation, approved by the GPSC on December 22, 2016, modifying the RCB Framework and outlining the process and recommendation for its continued implementation and application. The Joint Recommendation exempted behind-the-meter solar technologies from the RCB Framework, including, but not limited to, use in the determination of the RNR tariff. However, on June 7, 2017, the Commission approved the application of the RCB Framework to behind-the-meter programs, along with a revised RNR tariff.

Upon receiving Commission approval regarding the application of the RCB Framework, the Company proceeded to apply the RCB Framework in the evaluation of the Renewable Energy Development Initiative ("REDI") approved in the 2016 IRP, including both phases of the Utility

Scale Request for Proposals ("RFP"), the Distributed Generation RFP, the fixed-price Customer-Sited DG program, and the Commercial & Industrial program. In addition, the RCB Framework was applied to the Company's self-build evaluations sourced from the 2016 IRP and Solar Avoided Cost projections filed in Docket No. 16573, which establishes the annual price for the RNR tariff.

This Framework document is specific to Georgia Power and may differ from the application of the Framework by other retail Operating Companies. The RCB Framework methodology is consistent with how other resource additions are evaluated and, among other things, quantifies the non-dispatchable, intermittent nature of renewable resources and their effect on system reliability. The RCB Framework does not and is not intended to represent an endorsement of any particular form of valuation or compensation for any renewable resource in particular, nor does it represent any presumption regarding pricing structures or compensation arrangements that may be appropriate for any future programs or individual generator agreements undertaken in the various regulatory jurisdictions. Furthermore, this Framework by design cannot reflect full consideration of the various laws, regulations, and policies prevailing in the different jurisdictions served by Southern Company. Rather, the Framework establishes a means for determining an objective assessment of the costs and benefits of renewable resources within jurisdictions served by Southern Company. How the Framework may be used in various jurisdictions for the development of future programs, incentives, or pricing structures will be the prerogative of those jurisdictions.

## SECTION 3 – RENEWABLE COST-BENEFIT COMPONENTS CONSIDERED

This section describes the components that were considered for potential inclusion in the RCB Framework and identifies whether the component was included, excluded or considered for placeholder status.

### Definitions and Terms

**Avoided Energy Cost ("AEC"):** The marginal energy-related costs that are avoided on the Southern Company electric system in any given hour (including marginal replacement fuel costs, variable operations and maintenance, fuel handling, compliance related environmental costs, intra-day commitment costs, and transmission losses) because the load was served by the renewable generation.

**Capacity Worth Factor Table ("CWFT"):** The CWFT is the relative allocation of the value of capacity across the year and represents the relative reliability risk (i.e., risk of unserved energy) in one hour relative to all other hours.

**Distributed Behind-the-Meter ("DG-BTM"):** Solar generation at a customer's site where only a single bi-directional meter exists; generation is primarily consumed onsite to serve the customer load, with any excess energy delivered to the grid in accordance with applicable laws and tariff requirements. The size of this type of solar facility is typically less than 125% of the connected load.

**Distributed Greenfield ("DG-G"):** Central station solar generation facilities that are interconnected at the distribution level on an existing (non-dedicated) distribution feeder.

**Distributed Metered ("DG-M"):** Solar generation at or adjacent to a customer's site where the solar generation is metered separately from the load and delivered directly to the grid. This type of solar facility is typically less than 125% of the connected load.

**Economic Carrying Cost ("ECC"):** The capital and fixed operations & maintenance ("FOM") related cost of deferring an investment for one year. ECC represents the avoided cost of an investment for a given year.

**Flexible Resource:** Any resource that can be committed (i.e., brought online such that it is providing energy to the grid) in 30 minutes and fully dispatched (i.e., brought to its desired level) within 60 minutes.

**Incremental Capacity Equivalent ("ICE"):** The equivalent capacity value of a potential resource that is based on the resource's contribution to reducing expected reliability risk as compared to that of a dispatchable combustion turbine ("CT") resource.

**Long-Term Service Agreement ("LTSA"):** The long-term warranty and maintenance agreements on CT and combined cycle ("CC") facilities that define certain maintenance requirements as a function of certain unit operations.

**Renewable Energy Credit ("REC"):** A certificate, document, or record representing the environmental attributes of 1 megawatt-hour (MWH) of energy produced by a qualified renewable resource.

**Utility Scale-Distribution ("US-D"):** Central station solar generation facilities that are interconnected at the distribution level on a dedicated distribution feeder.

**Utility Scale-Transmission ("US-T"):** Central station solar generation facilities that are interconnected at the transmission level.

**Variable Energy Resource ("VER"):** A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.[1]

The following section provides detailed discussion on each component considered for inclusion in the RCB Framework and its current status as part of the RCB Framework.

## Avoided Energy Costs

Recommendation: Include Avoided Energy Costs. This item is a project-specific component.

[1] This definition was established by FERC: *Integration of Variable Energy Resources Notice of Proposed Rulemaking*, FERC Stats. & Regs. ¶ 32,664 at P64 (2010).

Description and Discussion: This item represents the marginal energy-related costs that are avoided on the Southern Company electric system in any given hour (including components associated with marginal replacement fuel costs, variable operations and maintenance, fuel handling, compliance related environmental costs, intra-day commitment costs, and transmission losses) because the load was served by the renewable generation. The Avoided Energy Costs component includes several subcomponents historically included in the Company's avoided costs and several components identified in various VOS studies, including the following:

**Avoided Fuel and Purchased Power Costs:** This item represents fuel costs as well as expenses associated with purchased power that are actually avoided because a portion of the load is being served by a renewable resource. ***Avoided*** Fuel and Purchased Power should be included as a ***benefit*** in the Framework, and should be calculated as part of the renewable-weighted Avoided Energy Cost.[2] As discussed in Section 4, the renewable-weighted Avoided Energy Cost used in the Framework reflects the projected fuel and technology expected to represent the marginal unit for dispatch in any given hour in which the renewable resource is expected to be producing electricity. It does not reflect any specific single fuel or any specific single technology. This approach is superior to limiting the analysis to a specific fuel or technology in the avoided cost calculation. The renewable-weighted Avoided Energy Cost approach determines the cost of the actual energy expected to be avoided on an hourly basis during the hours that the renewable resource is expected to be generating rather than a less robust approach of making an assumption regarding the technology and fuel that will be avoided.

**Avoided Generation Variable Operations and Maintenance ("VOM") Costs:** This item represents operational costs and maintenance costs that vary in direct proportion to the generation that is avoided because a portion of the load is being served by a renewable resource. ***Avoided*** VOM should be included as a ***benefit*** in the Framework and should be calculated as part of the Avoided Energy Cost.

**Avoided Water Consumption Costs:** Direct water consumption and treatment costs are included in VOM calculations. This item represents costs associated with water consumption by generating facilities that are avoided because a portion of the load is being

[2] The method for calculating Avoided Energy Costs can be found in Appendix C, while the method for using the Avoided Energy Costs to calculate a renewable-weighted Avoided Energy Cost is specified in Section 4.

served by a renewable resource. Currently, Southern Company already includes the withdrawal and treatment costs of the water in VOM costs, and thus the costs are reflected in Avoided Energy Costs. The merits of including a proxy for presumed “societal” costs and benefits, such as might be associated with avoided water use, are addressed separately in the Externalities component. Externality costs are speculative and very difficult to value with any degree of accuracy. Moreover, these costs represent an externality for which benefits do not accrue to the electric utility by avoiding them and, therefore, there is no benefit to be passed on to utility customers. Water consumption costs included in VOM are already a part of Southern Company’s Avoided Energy Costs and thus ***are included*** in the Framework calculations. It is recommended that the societal costs of avoided water consumption ***should not be included*** in the Framework.

**Avoided Environmental Compliance Costs:** This item represents the actual avoided costs of complying with existing environmental regulations because a portion of the load is being served by a renewable resource. Note that these costs do not specifically refer to fixed and sunk costs already incurred to bring the system into compliance – such as the cost of switching fuels, or building baghouses, scrubbers, or similar environmental controls. Such costs cannot be avoided once they have been incurred. Rather, this component represents the incrementally avoided environmental costs, which are primarily associated with avoided environmental allowance costs or consumables necessary for environmental compliance. Such costs are already included in Southern Company’s Avoided Energy Cost calculations. This specific component does not include any proxy for presumed societal environmental costs or benefits or anticipated environmental legislation or regulation. The merits of including a proxy for societal costs and benefits are addressed separately in the Externalities component, and the avoided costs and benefits of anticipated legislation or regulation cannot be properly known until a law is enacted or a final rule is established. ***Avoided*** compliance costs associated with meeting existing environmental regulations, which are already included in Avoided Energy Costs, should be included as a ***benefit*** in the Framework. However, societal avoided costs ***should not be included*** because the benefits do not accrue to the electric utility by avoiding them and, therefore, there is no benefit to be passed on to utility customers. It is acknowledged that as environmental laws and regulations change, the specific environmental compliance costs included in the costs and benefits of renewables will change.

Avoided Energy Costs as described above should be included as a ***benefit*** in the Framework.

**Fuel Hedging**

Recommendation: Do not include.

Description and Discussion: Certain industry studies presume that renewable resources can provide fuel hedging benefits in the form of decreased fuel cost volatility risk associated with the portion of load being served by a fixed price resource. Southern Company does not believe renewable resources provide such benefits, because such benefits derive primarily from the contractual obligation of the supplier to deliver under the contract at the specified price or suffer a contractual penalty for non-delivery. When a supplier has no firm obligation to provide output to the utility and may withdraw production at its convenience, there are no benefits. To the extent there may be a contractual obligation to deliver a set amount of energy, the calculation of a potential hedge benefit nonetheless requires a degree of speculation that would significantly diminish confidence in the results and would therefore be inappropriate in the regulated environment. In addition, there are risks associated with fixed price contracts that could offset any potential fuel hedging benefits.[3] Any incorporation of analysis to consider fuel hedging benefits would also need to take such risks into account.

Furthermore, Southern Company has specific fuel hedging programs already in place that are regulated and overseen by their respective regulatory authorities. Considering additional fuel hedging benefits resulting from renewable contracts may require incorporating those contracts into the fuel hedging program. Rather than specifically incorporating those projects into the fuel hedging program, Southern Company maintains a diversified fleet of generating resources – including renewable resources – to provide a portfolio-based hedge against fuel price volatility. There is no precedent within Southern Company to ascribe any particular fuel hedging value to the economic evaluation of any fixed price contract. To ascribe such value for one resource while not ascribing similar value to other resources would represent an inconsistent approach in resource evaluations, resulting in the biasing of one resource type in favor of another resource type. In the event that, at some point in the future, evaluation

[3] Such risks would include, for example, the risk that there would be significant technological advances that lower costs, the risk that loads may not materialize as expected, and the risk that fuel prices will drop during the course of the PPA.

procedures for all such resources were to include these theoretical fuel hedging benefits, they would be included in the RCB Framework as well.

Fuel hedging associated with renewables ***should not be included at this time*** in the Framework.

## <u>Deferred Generation Capacity Costs</u>

Recommendation: Include deferred generation capacity costs. This item is a project-specific component.

Description and Discussion: This item represents generation capacity costs that are deferred because a portion of the load is being served by a renewable resource. In determining such costs, the intermittent and non-dispatchable nature of renewables must be factored into the analysis. Southern Company uses an ICE factor, which establishes a capacity value based on a resource's capacity worth across the entire year, not just a few hours. This method approximates the reliability of a renewable resource relative to the reliability of a dispatchable CT resource as opposed to just determining the peak load carrying capability.

In Georgia, renewable resources receive capacity value credit in the year when the next capacity need is forecast. Southern Company already employs a well-established coordinated planning process to determine the next capacity need. Through that process, generation capacity needs are identified and expansion plans are established to meet load serving requirements. Generating resources that are added to the system through that process have a capacity value that results from the fact that such capacity was added to meet a specific need. When considering changes to existing resources (such as generation retirements), it is appropriate to consider that value in all years. However, when resources are added to the system outside of the coordinated planning process or for reasons other than a specifically stated capacity need, the assignment of capacity value to that resource may be influenced by other considerations, such as when the resource expansion plan indicates a capacity need. Therefore, when performing resource evaluations, Georgia Power will give capacity credit based on the first year of capacity need as indicated in the Company's resource expansion plan.

Further, there may be a limit to the amount of capacity that can be deferred as a result of renewable resources, particularly with respect to solar resources. For example, as more solar generation is added to the system, the effective summer peak demand for planning purposes (i.e., the effective load served after taking into account the output of the intermittent resources – modeled in Appendix B as a reduction in load) will begin to shift from the mid-to-late afternoon hours into the evening hours. At significantly high penetrations of solar generation, the effective system peak demand will occur after sunset and no further amount of solar will offset that peak demand. This result will ultimately be reflected through significantly reduced, if not eliminated, capacity values for the summer season. Similar effects for the early morning hours are possible for the winter season but would be less pronounced. As indicated by the reductions in summer effective peak demand in Appendix B, capacity deferral benefits associated with higher penetrations of solar generation will be greatly reduced such that they are likely to be eliminated with penetrations at levels significant enough to shift the effective peak demand to dusk. Southern Company's ICE factor determination – which can capture these effects for both summer and winter – is designed to capture this change in capacity through use of the CWFT. (See Section 4 for a description of how the CWFT is applied.) Although the potential for emerging storage technologies may mitigate this impact and restore some of this lost capacity value, those storage assets would need to be paired with the renewable resource and the costs and operational impacts evaluated simultaneously. If a specific project proposal contains storage technology, the potential for including capacity credit as a result of the storage will be evaluated on a case-by-case basis.

Finally, it should be noted that since the evaluation of deferred generation capacity costs implicitly presumes that the renewable generation resource will be available long term, the application of deferred generation capacity costs should only be included in the Framework when there is a reasonable expectation that the renewable resource will be available well into the future. In those cases for which no such reasonable expectation exists, deferred generation capacity costs should not be included in the Framework calculations.

Several components identified in various VOS studies are included as part of the Deferred Generation Capacity Costs component, including the following:

**Deferred Reserve Capacity Costs:** This item represents reserve capacity costs that are deferred because a portion of the load is being served by a renewable resource. The basis for including these costs is premised in part on the recognition of renewable resources as a net load reduction. That presumed net reduction in load caused by renewable resources is then presumed to not only defer direct capacity, but also the planning reserve capacity needed to serve that load. Southern Company does not consider a renewable resource to be a reduction in load,[4] but rather a non-dispatchable generation resource. As such, Southern Company views those resources, along with all other resources, as generating capacity available to serve load. The planning process identifies an amount of capacity, including reserves, necessary to reliably serve that load. For renewable resources, Southern Company uses the ICE factor to calculate a capacity equivalent on a basis that has equivalent reliability to CT capacity. In so doing, the renewable resource becomes another equivalent resource for meeting the planning reserve requirement. The calculation of capacity deferred by renewable resources is, therefore, not solely a calculation of deferral based on the load-serving capacity requirement, but of deferral based on total capacity requirements including reserve requirements. Avoided capacity cost calculations, therefore, already account for these reserve capacity benefits. Deferred Reserve Capacity Costs should be included as a ***benefit*** in the Framework as an integrated part of the Deferred Generation Capacity Cost component.

**Deferred Fixed Operation and Maintenance Costs:** This item represents FOM costs that are deferred because a portion of the load is being served by a renewable resource. To the extent capacity costs are deferred, it is also appropriate to take into account the associated FOM costs. For Southern Company, the FOM costs are already included in the Economic Carrying Cost associated with the avoided capacity. ***Deferred*** FOM Costs should be included in the Framework as a ***benefit*** as an integrated part of the Deferred Generation Capacity Cost component only to the extent it relates to deferred generation capacity.

Deferred Generation Capacity Costs, properly adjusted by an ICE factor, should be included as a ***benefit*** in the Framework when there is reasonable assurance that the renewable resource will be present well into the future. The prevailing regulatory environments also must be considered in calculating Deferred Generation Capacity Costs.

**Deferred Transmission Investment**

Recommendation: Include as either a cost or a benefit as appropriate for the specific location and type of renewable facility. This item is a technology-specific component for distribution level implementations (transmission level implementations are evaluated on a case-by-case basis).

[4] Although renewable resources are not to be considered a reduction in load, modeling limitations sometimes require such generation to be evaluated as if it were a reduction in load. See, for example, Appendix B.

Description and Discussion: This item represents the potential cost or benefit of deferred transmission investment associated with a renewable resource. In Southern Company's view, the benefit of deferred transmission investment is highly dependent upon the type and location of the renewable facility. In addition – as with deferred generation capacity – there is a limit to the amount of transmission that can be deferred due to solar generation in the summer because of the shift of the peak demand from the daylight hours to the night-time hours. During the winter, the system peaks generally occur just before or at dawn and after dusk. For these reasons, solar generation will not have an appreciable impact on deferring future transmission capacity investments.

For larger, utility scale facilities, there may be a transmission cost rather than a transmission benefit, depending upon the location and size of the facilities. For these applications, there are well-established, existing processes in place for determining the appropriate transmission impacts. For wind generation outside of the Southern Company Balancing Authority Area ("SBAA"), this requires either the purchase of transmission service and/or construction of new transmission facilities to import wind energy into the region. Therefore, deferred transmission investment for utility scale implementations should be included in the Framework, but whether such is deemed a ***cost*** or a ***benefit*** should be determined on a case-by-case basis.

For facilities interconnected at the distribution level, there may be some deferred transmission cost, but the amount still depends highly on the location and quantity of the resource. Therefore, geographic penetration assumptions will influence the deferred transmission investment calculation. Also, as with deferred generation capacity, the deferred transmission benefit should only be included in the Framework if there is a reasonable expectation that the resource will be available well into the future. For distribution level implementations, the deferred transmission should be included as a ***benefit*** in the Framework when there is reasonable assurance that the resource will be available long term.

**Reduced Transmission Losses**

Recommendation: Include as a cost or benefit depending upon the specific location. This item is a project-specific component.

Description and Discussion: This item represents the benefit of Reduced Transmission Losses associated with a renewable resource. This benefit comes in two forms – reduced energy losses and reduced capacity losses.

The reduced energy losses on the transmission system represent the reduced generation (in MWH) resulting from a reduction in transmission system losses due to the renewable resource. Most studies take these transmission losses into account. With respect to energy losses on the transmission system, Southern Company already includes the impacts of transmission losses necessary to deliver generation to load in its projected Avoided Energy Costs.

The reduced capacity losses on the transmission system represent the reduction in demand (MW) on the transmission system resulting from a reduction in transmission system losses due to the renewable resource. With respect to these capacity losses, none of the avoided energy cost calculations include the transmission capacity loss impacts. However, they are included as part of the Deferred Transmission Investment calculation used by Southern Company. Therefore, the two loss components (energy and demand) are both considered but are determined separately as part of the determination of other components.

The impact of transmission capacity losses is dependent upon where and how a renewable resource is connected to the grid. Distributed resources will typically provide transmission capacity loss benefits. However, the larger scale projects – even those connected to the distribution system – may be either a transmission capacity loss benefit or cost depending upon the location. This is because the larger projects are typically designed specifically to back feed into the transmission system rather than serve local load. Depending upon the location of these larger scale systems, this may actually increase losses rather than offset them.

Reduced Transmission Losses – both capacity and energy – should be included in the Framework. Transmission energy losses should be included as a ***benefit*** and should be included through use of the projected Avoided Energy Costs. Transmission capacity losses should be included as a ***benefit*** for distributed resources and calculated as part of the Deferred Transmission Investment calculation, but for larger scale projects connected to the distribution or transmission system, transmission capacity losses should be evaluated on a case-by-case basis to determine whether there is a ***benefit*** or a ***cost***.

**Deferred Distribution Investment**

Recommendation: Do not include.

Description and Discussion: Certain industry studies presume there is a benefit of deferred distribution investment associated with distributed renewable resources. Southern Company does not believe distributed renewable generation provides such benefits.

Per IEEE 1547, the IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems, Southern Company requires all distributed resources (including solar generation facilities) to cease energizing the distribution system upon occurrence of a fault on the distribution system. These resources are required to stay off-line for up to five minutes after the distribution system voltage and frequency are restored to ranges specified in ANSI C84.1 Standard. Therefore, the distribution system must be capable of serving 100 percent of the load during this timeframe. As a result, while the impacts of renewable resources on the distribution system (particularly solar) must be properly taken into account, planning of the distribution system must assume that the feeders containing such generation are still required to carry the full load connected to these circuits, thereby negating any potential deferment of distribution investment.

Another concern with solar in particular is the relationship of intermittent cloud cover to solar generation output and load on the distribution system in a specific geographic location. Cloud cover reduces the amount of solar generation from a solar facility in minutes, if not seconds. However, residential and commercial load on the circuit, including thermal load, will not diminish in the same timeframe. Thermal inertia present in physical objects such as brick walls will delay any change in load at businesses or residences, potentially for hours, during periods of intermittent cloud cover. Since the load changes very little, if at all, during a period in which the amount of solar generation is decaying, the net effect is that the distribution system will be required to serve the load that had been served by the solar facility before the cloud cover. Similar concerns would exist for a distributed wind resource as it relates to the intermittency of prevailing winds.

An additional concern is the fact that it is estimated that approximately 30 percent of distribution circuits across the Southern Company electric system are winter peaking circuits. Because the winter peaks generally occur just before or at dawn and after dusk, solar generation on these circuits will have no positive impact on deferring future distribution capacity investments. This concern is compounded by the fact that Southern Company is trending towards becoming a dual-season peaking utility. As such, the trend will be that larger numbers of distribution feeders will peak in the winter rather than in the summer.

In summary, Southern Company believes that distribution circuits will still need to be sized to handle the full burden of the load so that the load can continue to be served when the intermittent resource is unavailable.

Deferred Distribution Investment ***should not be included at this time*** in the Framework. It is acknowledged that future changes in laws, standards, and regulatory structures could result in the need to re-examine whether this component should be included in the Framework.

## Reduced Distribution Losses

Recommendation: Include as a cost or benefit depending upon the specific location. This item is a project-specific component.

Description and Discussion: This item represents potential impact on distribution losses associated with distributed renewable resources and is not applicable to utility scale resources. This impact, increase or decrease, comes in two forms – capacity losses and energy losses. The change in capacity losses would be represented by the change in demand (MW) on the distribution system associated with a change in losses on the distribution system due to the distributed generation. The change in energy losses represents the change in generation (in MWH) associated with a change in losses on the distribution system due to the distributed generation. Unlike transmission losses, Southern Company does not include the impact of distribution losses in its projected Avoided Energy Costs. Therefore, there would be both an Avoided Energy Cost component and a Deferred Capacity Cost component to the Reduced Distribution Losses calculation.

As stated previously in the Deferred Distribution Investment section, there is no deferred distribution capacity investment created by renewable resources. Because there is no deferred distribution capacity investment, it would therefore follow that there would be no deferred distribution investment associated with a reduction in the capacity component of distribution losses.

A determination of distribution losses is a challenging proposition, and one dependent on factors such as the amount and location of load on a circuit at any given time, and the amount and location of renewable generation on the circuit at the corresponding time. For a renewable facility located closer to a given load, losses should be reduced (as the load would be expected to consume the energy before any losses occurred). For renewable generation located farther from the load, losses would increase.

It is reasonable to assume that small, customer-sited renewable generation would be consumed by load that is located close to the facility. Therefore, losses are reduced in such instances. However, in instances with larger customer-sited or greenfield sites, the distributed generation may be larger than the corresponding load or may not be sited close to the corresponding load. In these instances, losses on the distribution system may be reduced or increased, depending on the location and amount of load and solar generation. Therefore, the determination of distribution losses may be different for the different categories of distributed generation.

Reduced Distribution Losses should be included in the Framework as a ***benefit*** for Distributed Generation including Behind-the-Meter and Metered. Although it is presumed that Greenfield facilities are a benefit in the aggregate, DG-G facilities may have locational implications that require a different methodology for determining the benefit. It is recommended that DG-G projects be evaluated on a case-by-case basis to determine whether Reduced Distribution Losses should be included as either a ***benefit*** or a ***cost*** depending upon the project specific evaluation and circumstances.

**<u>Distribution Operations Costs</u>**

Recommendation: Include as a placeholder.

Description and Discussion: This component reflects the operation and maintenance costs that Southern Company would not have otherwise incurred except for the addition of distributed generation on the system. These costs include expenses that are related to ensuring safety, system reliability, and power quality. There are three primary areas of cost impacts that fall into this category.

- First, there may be impacts associated with Southern Company's conservation voltage reduction programs. These load reduction programs are based upon the premise of reducing demand at system peak by reducing distribution voltage. Distributed solar generation will have the effect of raising distribution voltage, potentially making these programs less effective.
- Second, there are impacts to the operation and maintenance costs of voltage regulators and other related distribution equipment. The voltage swings on the distribution system caused by the intermittent nature of the renewable generation will create additional duty on this equipment, thereby increasing required maintenance or shortening the equipment life.
- Third, distributed renewable resources will have an impact on automatic fault isolation and restoration schemes. Renewable generation will mask actual load. This may result in limiting the system's ability to restore service or in overloading adjacent circuits upon a restoration attempt.

These Distribution Operations Costs are currently included as a ***placeholder*** in the Framework.

**<u>Generation Remix</u>**

Recommendation: Include as a cost or benefit as appropriate. This item is a technology-specific component.

Description and Discussion: This item represents the impact that a large penetration of renewable resources will have on both system commitment and dispatch, as well as the expected future generation expansion plan build-out of the system associated with the addition of a renewable resource. The Avoided Energy Costs and Deferred Generation Capacity Costs are determined using a marginal cost methodology. The marginal cost approach is suitable for small, incremental additions. In this approach, a system mix model is developed reflecting the base case assumptions and generation resource additions over the planning horizon and the marginal energy and capacity requirements associated with that system mix are determined. However, when considering larger scale additions to the system, such as 1,000 MW of renewable resources, it is possible that the mix of generation resource additions included in the base case could be changed if the plan were reoptimized to consider the larger scale addition, causing some changes to Deferred Generation Capacity Costs and to Avoided Energy Costs. Generation Remix values are derived and then used to adjust the Generation Capacity Costs and Avoided Energy Costs (positively or negatively) to reflect the impacts of a larger scale addition to the system.

Generation Remix should be included as a ***cost or benefit as appropriate*** in the Framework.

**Ancillary Services**

Recommendation: See specific recommendations for each ancillary service below.

Description and Discussion: This item represents the impacts to ancillary services associated with renewable resources. While some studies claim there are ancillary services benefits associated with renewable resources, Southern Company believes that the intermittent nature of renewable resources actually increases the utility's cost to supply such services. The following outlines each of the Open Access Transmission Tariff ("OATT") ancillary services categories and how Southern Company views the impacts of renewable resources on the cost to provide such services.

**Scheduling, System Control, and Dispatch:** The Scheduling, System Control, and Dispatch Ancillary Service components represent the service to transmission customers for scheduling the movement of power through, out of, within, or into a Balancing Authority. There are no benefits to this ancillary service associated with renewable resources. In fact, there are likely to be increased system costs associated with the scheduling, system control, and dispatch of such generation. Any such increase in cost would likely be captured as part of the "Support Capacity" calculation (see Support Capacity section below). As such, this item is a technology-specific component.

**Reactive Supply and Voltage Control:** The Reactive Supply and Voltage Control Ancillary Service components represent the service associated with the maintenance of transmission voltages on the Transmission Provider's facilities within acceptable limits. Generators interconnected at the transmission level, including renewable facilities interconnected at the transmission level, are required by interconnection procedures to have the ability to maintain system voltage schedule. This does not avoid any other reactive power supply, but rather provides the reactive power necessary to deliver the real power produced by that facility. For renewable resources interconnected at the distribution level, there may be some benefits associated with reactive supply and voltage control if the resource is implemented with smart inverters. However, there is no guarantee (without a specific requirement to do so) that distributed resources will install these smart inverters. Nor – even if such smart inverters are installed – is there any guarantee that there will be sufficient capability installed (e.g., for solar, a combination of DC panel capacity, inverter capability, and appropriate control technology) to take advantage of that capability while also providing the expected real power benefits. Finally, even if all of these are present, without some requirement for interconnected facilities to meet voltage control requirements, the utility will not have access to the use of such capability. Currently, there are no such requirements for renewable resources connected at the distribution level, and resources at the sub-transmission level (i.e., 46kV and/or 69kV) are required to maintain a fixed power factor rather than control voltage.[5] Absent these guarantees, the intermittent nature of renewable resources will create significant voltage fluctuations on the distribution system and sub-transmission system that will need to be controlled. Therefore, the utility will be required to implement measures to mitigate these voltage fluctuations. The implementation of these mitigating measures will mean increased costs that need to be considered in the costs and benefits of renewable resources. Even when the prerequisites described above are present and such capability exists, there is still no guarantee that the positive impacts will outweigh the negative impacts. The existence and scope of such impacts would require further study before any benefits could be attributed. Reactive Supply and Voltage control are currently included as a ***placeholder*** in the Framework.

**Regulation:** The Regulation Ancillary Service represents the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). The intermittent nature of renewable resources creates an increased need for Regulating Reserves on the system. Regulation should be included as a ***cost*** in the Framework. Note: This cost is being included as part of Support Capacity below. As such, this item is a technology-specific component.

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[5] For transmission interconnections, voltage guidelines are established through OATT Large Generator Interconnection Agreement and Small Generator Interconnection Agreement documents available on OASIS. For distribution interconnections, voltage regulation guidelines are specified in both the Southern Company Distribution Interconnection Policy and Interconnection Agreement documents and are based on ANSI C84.1, Table 1, Range A and IEEE 1547 - 2003.

**Energy Imbalance:** The Energy Imbalance Ancillary Service represents the difference between the energy scheduled and the actual energy delivered to a ***load*** located within a Balancing Authority over a single hour. Renewable resources are not dispatchable and therefore provide no Energy Imbalance Ancillary Service benefit. However, because they are ***resources*** and ***not load***, it likewise does not cause any specific increase in energy imbalance costs. Therefore, Energy Imbalance ***should not be included*** in the Framework.

**Operating Reserve-Spinning and Operating Reserve-Supplemental:** The Operating Reserve Ancillary Service represents the maintenance of adequate generation capacity necessary to satisfy applicable North American Electric Reliability Corporation ("NERC") requirements for Spinning and Supplemental Operating Reserves. Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Currently, renewable resources do not have a direct impact on the amount of Spinning and Supplemental Reserves required by NERC standards, but they do have an indirect impact because Spinning and Supplemental Reserves may be dispatched to mitigate the impacts associated with renewable resource uncertainty. In addition to the uncertainty caused by its intermittency, renewable resources are also uncertain because their output is difficult to forecast with any significant degree of accuracy. Regulating Reserves are sufficient to meet the intra-hour intermittency and renewable forecast error volatility only to the extent such volatility can be corrected within 10 minutes (the timeframe in which Regulating Reserves are deployed). Outside of that 10-minute window – which is primarily where forecasting errors are manifested – other available resources (primarily Spinning and Supplemental Reserves) are deployed to correct these volatilities. Spinning and Supplemental Reserves have a very specific purpose under NERC criteria,[6] which is to respond to contingencies on the system. The intermittent nature of renewables, including forecasting errors, is not currently considered a "contingency" *per se*, but in order to keep from violating NERC disturbance control standards, Spinning and Supplemental Reserves (in addition to Regulating Reserves) will likely have to be deployed to mitigate these volatilities. If Spinning and Supplemental Reserves are deployed for any reason (including the need to handle the intermittent and forecast error aspects of solar generation), NERC standards require that they be replaced within a specific timeframe. Therefore, significant penetrations of renewables will impose the need for a certain amount of flexible (i.e., responsive in the 30- to

[6] See NERC Reliability Standard BAL-002-0 Disturbance Control Performance.

60-minute time frame) resources to be available to replace the Spinning and Supplemental Reserves deployed to mitigate forecast errors associated with solar generation. Southern Company refers to these flexible resources as Support Capacity. Therefore, while it is noted that Operating Reserve-Spinning and Operating Reserve-Supplemental are impacted by renewable resources, they ***should not be included directly*** in the Framework; but ***rather the impacts should be included as part of Support Capacity***, which is described below. As such, this item is a technology-specific component.

**Support Capacity**

Recommendation: Include as a net cost; annual Support Capacity production costs can be a benefit. This item is a technology-specific component.

Description and Discussion: Support Capacity represents the impact that renewable resources have on the reliability of the System. It can be viewed as additional resources needed to "back up" the renewable resource because of its non-dispatchable, intermittent nature and is modeled as a reduction in the overall capacity value of the resource resulting from that intermittency. Support Capacity is needed for several reasons, including (a) replacement of additional Regulating Reserves needed to handle the volatility of the output of the intermittent resources, (b) accounting for the impact of the forecast error associated with predicting the output of the intermittent resources, and (c) managing increased generation ramping and load following requirements associated with heavy penetrations of non-dispatchable renewable resources.[7] There may be some ability in the existing system to handle these flexible dispatching requirements for two reasons. First, prior to the year of system capacity need, there is excess generation capacity that is available to meet the capacity component of this incremental requirement. Second, not every hour of the year is reliability constrained, and so only the hours that are reliability constrained contribute to the capacity component of this incremental requirement. The methodology for determining Support Capacity will take both of

[7] Some commentators have suggested that demand-side resources can meet these flexibility requirements. However, due to the immediate and specific response required to handle the intermittent nature of renewable resources, no such demand response programs currently exist in Southern Company's service territories that would be able to provide a response that is timely (in the 30-60 minute time frame), absolutely dependable in quantity, and allowable to be used for this specific purpose. The intent of this process is to establish a cost benchmark for Support Capacity, not to explore all possible alternatives to meet Support Capacity needs.

these considerations into account. However, even for lower levels of solar penetration, there will still be ***production costs*** that will need to be considered even in the early years of the analysis. Both production and capital costs must be considered.

Support Capacity should be included as a net ***cost*** in the Framework. See Appendix D for a more detailed write up on the need for Support Capacity.

## Bottom Out Costs

Recommendation:  Include as a placeholder.

Description and Discussion:  This item represents the costs associated with increased risk and occurrences of bottom out conditions caused by renewable resources. Bottom out conditions occur when the demand on the system reaches a point that is so low that online generating resources can no longer reduce their output without de-committing, i.e., turning off. Many lower cost, high load factor generating resources have long minimum downtimes, meaning that once they de-commit, they must remain offline for an extended period of time before coming back online. When the system reaches a bottom out condition, decisions to bring these lower cost resources offline may result in those resources not being able to serve the upcoming high demand period. The subsequent high demand period must therefore be served with higher cost, more flexible resources. This effect is especially prominent in the winter when the load pattern is characterized by a sharp morning peak and a sharp evening peak with a low load period in between. Renewable resources increase this risk in the winter as well as in the lower load spring and fall periods because it adds non-dispatchable generation when the system is at its lowest demand. Appendix B demonstrates an example of how solar generation can increase the risk of bottom out and shows the phenomenon that has been referred to in the industry as the “duck curve.”  To the extent modeling capabilities can capture such costs in the recommitment of the system, these costs have already been included as part of the Generation Remix calculation. However, to the extent such recommitment efforts are insufficient to eliminate bottom out conditions caused by the increased penetration of renewable resources, this category captures these additional costs.

Bottom out costs, which for purposes of this Framework refer to the costs not captured in the recommitment of the system, are currently included as a ***placeholder*** in the Framework. Recommitment costs are already included in Generation Remix.

## Improved Grid Security/System Protection

Recommendation: Do not include.

Description and Discussion: This item represents the value of increased reliability and security of the grid caused by distributed renewable resources, and so is only applicable to distributed renewable generation.

Proponents of deriving a value from these purported reliability benefits attribute them in part to localized islanding of the system during times of system outages. However, existing IEEE 1547 guidelines and Southern Company's policies prohibit islanding at the distribution level, a condition in which part of the utility's system is served by distributed generation while that part is electrically separated from the rest of the system. Therefore, any such "benefits" could only be realized as a result of operating the distribution grid in a manner directly conflicting with existing standards and policies. Georgia Power believes that this is not in the best interests of customers.

Moreover, while it may be theoretically possible to analyze the existence and extent of such benefits, including the consideration of benefits associated with islanded operation, this level of analysis would not be appropriate at this time given the requirements and prohibitions associated with current, prevailing standards and policies.

Grid Security/System Protection ***should not*** be included in the Framework. Future changes in laws, standards, and regulatory structures, however, could result in the need to re-examine whether this component should be included as a cost or benefit of renewable resources.

## Avoided Renewable Energy Credit Costs

Recommendation: Do not include.

Description and Discussion: This item represents the avoided costs associated with acquiring RECs to meet a specified Renewable Portfolio Standard ("RPS"). At present, none of the jurisdictions in which Southern Company provides retail service has an RPS. As such, there are no REC costs to be avoided. For this reason, there is no basis to consider the avoided value of RECs, if any.

REC costs ***should not be included at this time*** in the Framework.

**Long-Term Service Agreement Costs**

Recommendation: Include as a placeholder.

Description and Discussion: This item represents the increased LTSA costs associated with increased generation ramping and startups of CTs and CCs that may result from the intermittent nature of renewable resources. Anticipated starts-based maintenance is included in existing O&M values. However, those O&M values are based upon a presumption of future anticipated starts. As indicated in the section on Support Capacity above, increased penetration of intermittent resources will create the need for increased use of flexible resources such as CTs. It will also create increased cycling of resources such as CCs during low load periods. This will increase the use of these resources for load following (generation ramping) and will also increase the number of starts incurred by these resources. As such, it will affect the LTSA maintenance costs for those resources and ultimately is projected to result in increased operation and maintenance costs not currently accounted for in the avoided energy costs.

Long-Term Service Agreement costs are currently included as a ***placeholder*** in the Framework.

**Target Reserve Margin Cost**

Recommendation: Do not include.

Description and Discussion: This item represents the increased costs associated with an increased target reserve margin associated with intermittent renewable resources. These increased costs are additional reliability impacts not otherwise included in the Support Capacity or Deferred Generation Capacity components but attributable to renewable resources. As renewable penetration increases, the effective load profile (i.e., that served by the remaining, non-intermittent resources) of Southern Company will also change. As these changes to the effective load profile occur, Southern Company's target planning reserve margin will capture such changes to the effective load profile, which, in turn, may impact the CWFT. In the event that the target planning reserve margin does change in a manner that is definitively attributable to renewable resources, there would be very real impacts (costs or benefits, depending upon whether the target reserve margin increases or decreases) to Southern Company's customers.

The cost or benefit impacts on the long-term planning target reserve margin, whether it is a cost or a benefit, are currently captured in the Company's Reserve Margin Study and thus ***should not be included at this time*** in the Framework.

**Program and Administrative Costs**

Recommendation: See individual categories below.

Description and Discussion: This item represents the various program and administrative costs associated with implementing a renewable resource program. Distributed renewable resources, however, could be added to the electric system in the absence of a formal program. The intent of this category is to capture program and administrative costs that may be associated with a formal program and inclusion of these items in a cost-benefit analysis. The discussion and recommendations below generally address the items themselves and whether they should be included as either a cost or a benefit if such is allowed or proscribed by Georgia jurisdictional requirements.

**Interconnection Costs:** These are the directly assignable generation interconnection costs that are typically assigned to the distributed generator at the time of implementation.[8] Because they are charged to the specific generator, these costs ***should not be included*** in the Framework.

**Program Costs:** These are the directly assignable costs that the retail Operating Companies may experience to promote and administer any particular renewable program. These would include any directly assignable costs that are not charged to the renewable

[8] Transmission interconnection costs are determined in accordance with FERC Large and Small Generation Interconnection procedures.

resource at the time of implementation.  These costs are currently included as a ***placeholder*** in the Framework.

**Administrative Costs:** These are the indirect administrative and general costs incurred by the retail Operating Companies that would not otherwise have occurred except for the renewable program. These costs include expenses related to forecasting and accounting for the intermittent and unpredictable nature of the renewable resource. Additional costs are borne due to the administration requirements of the PPA's, including compliance and reporting activities. These costs are currently included as a ***placeholder*** in the Framework.

**Accounting Costs:** These are the imputed financing costs that the retail Operating Companies may experience depending upon how the renewable programs are structured, including such costs as imputed capital associated with certain types of leases and impacts associated with Variable Interest Entities. Whether such costs exist depends entirely upon how the programs are structured. These costs are currently included as a ***placeholder*** in the Framework.

**<u>Market Price Mitigation</u>**

Recommendation: Do not include.

Description and Discussion: This item represents the potential reduction in market prices that results from the penetration of renewable resources into the market. Some studies suggest that the reduction in market prices is significant and should be considered. However, most studies making such recommendation do so based on the fact that market price mitigation is necessary in those markets (e.g., in Locational Marginal Pricing markets) to fully capture the avoided cost benefit. This is especially true given the fact that many of those studies presumed natural gas to be on the margin and some even determined avoided fuel costs using an assumed, guaranteed natural gas price. Therefore, the market price reduction calculation is an attempt to capture the total avoided costs experienced by customers in that market. By comparison, Southern Company does not have a market structure in which costs for all customers are determined by the cost of the marginal generating unit. As such, there are no such corresponding benefits to Southern Company. Therefore, the avoided cost calculations anticipated to be used by Southern Company is sufficient for capturing the benefits to the customers in this market.

Market price mitigation ***should not be included*** in the Framework.

**<u>Externalities</u>**

Recommendation: Do not include.

Description and Discussion: This item represents the many potential externalities that are often recommended to be included in the determination of the value of renewable resources. There are a number of components that stakeholders in the solar industry have proposed to be included in cost-benefit analyses for renewables related to purported benefits that are unknown, speculative, or not readily quantifiable. Such externalities include presumed benefits such as ***non-compliance related environmental benefits***, ***anticipated future (as yet undefined) environmental compliance costs, health benefits, economic development benefits, the value of civic engagement and awareness of renewable energy, the long-term societal value of renewables, and the like.*** These purported benefits do not accrue to Southern Company and thus cannot be passed along to customers. Accordingly, these are not appropriately considered in a cost-benefit determination.

Externalities ***should not be included*** in the Framework.

## SECTION 4 – RENEWABLE COST-BENEFIT COMPONENT METHODOLOGY

**Avoided Energy Costs**

As indicated in Section 3, a number of the components included in the RCB Framework are included in the determination of the Avoided Energy Costs, including fuel and purchased power, VOM, environmental compliance, and transmission energy losses.

For purposes of the RCB Framework, it is recommended that the "base case" scenario Avoided Energy Costs[9] be used for determining the appropriate renewable resource Avoided Energy Costs. The details for how the Avoided Energy Costs are calculated and how its subcomponents are all incorporated into the Avoided Energy Costs can be found in Appendix C.

The specific renewable resource Avoided Energy Costs used in the Framework should be calculated by multiplying – on an hourly basis – the hourly renewable generation profile (in MW) by the appropriate System Avoided Cost (in $/MWH) for that same hour. The sum of this product across all 8,760 hours for the year (8,784 hours during leap years) represents the avoided energy cost for that year (in dollars). This annual sum is divided by the annual renewable generation (in MWH) to give a single avoided energy cost (in $/MWH) for the year. This calculation is then performed for each year of the study period. The equation for this calculation is as follows:

$$AEC_j =$$

Where:

$AEC_j$ = the avoided energy cost in year *j (measured in $/MWH);*

*RGP(i,j)* = the renewable hourly generation profile for hour *i* in year *j (measured in MWH)*; and

*SAC(i,j)* = the System Avoided Cost for hour *i* in year *j (measured in $/MWH).*

**Deferred Generation Capacity Costs**

[9] These avoided costs are available as a result of Southern Company's annual Integrated Resource Planning and Energy Budgeting processes. The current expected case scenario is the Moderate Gas $0 Carbon scenario.

The deferred capacity cost methodology incorporates two of the identified components from Section 3, deferred capacity costs and deferred FOM costs.

The aggregate amount of capacity credit to be included should be based upon the impact that the renewable profile would have on system reliability as determined by the CWFT. This process results in the determination of the ICE factor for the renewable project. The incremental capacity equivalent itself (in MW) is calculated by multiplying the hourly CWFT by the renewable hourly generation profile. This product is then summed by hour across the year. The sum for the 8,760 hours in the year (8,784 hours during leap year) represents the total capacity value (in MW) in that year for the renewable project. The ICE factor is this MW value divided by the nominal capacity installed. The capacity equivalent (in MW) is then multiplied by the value of generation capacity to be deferred, which includes FOM impacts, to calculate the total deferred generation capacity cost benefit for the year. The formulas for the above calculations are as follows:

$$\textit{Deferred Capacity Cost}_j = \textit{Capacity Value}_j \times \textit{Capacity Equivalence}_j$$

Where:

*Deferred Capacity Cost*$_j$ = Deferred Capacity Costs in year *j (measured in \$);*

*Capacity Value*$_j$ = value of deferred generation capacity in year *j* (measured in \$/kW); and

*Capacity Equivalence*$_j$ = capacity equivalence in year j as defined by the equation below (measured in kW).

$$\textit{Capacity Equivalence}_j =$$

Where:

*CWFT (i)* = the capacity worth factor for hour *i* in any given year (measured in %); and

*RGP(i,j)* = the renewable generation profile in hour *i* of year *j (measured in kW).*

And finally,

$$\textit{ICE factor}_j = \textit{Capacity Equivalence}_j \,/\, \textit{Nominal Value of Resource}$$

Where:

*ICE factor*$_j$ = Ice Factor in year *j; and*

*Nominal Value of Resource = maximum delivered MW to the AC system.*

**Deferred Transmission Investment**

As discussed in Section 3, the transmission impacts associated with utility scale renewable generation may be either a cost or a benefit depending upon the circumstances, and so the impacts of utility scale renewable generation should be evaluated on a case-by-case basis according to established generator interconnection procedures. Impacts of widely distributed generation should be determined as described below.

The smaller size and varied location of DG should be evaluated in a system-wide study based on the assumed future DG penetration. The deferred transmission investment costs and benefits associated with the addition of DG would be determined by evaluating two alternative future system scenarios, one with and one without additional DG, to determine the transmission investments and in-service timing of projects necessary over the study horizon for each scenario. The DG analysis is performed in a similar manner to traditional 10-year transmission expansion planning, except for considering a longer-term planning horizon (≈20 years in the current study), and the analysis focuses on how the required in-service date of any identified projects are impacted by DG.

The starting point year chosen for the study is based on the last known year of firm, state commission-approved, resource decisions for load-serving purposes. Since future generation to serve future load growth over the longer-term study period has not yet been determined, the ultimate location and magnitude of any future generation is speculative and uncertain. Therefore, to avoid locational impacts to the transmission system driven solely by the assumed placement of the new generation, new generation to serve load growth is modeled as proxy generator injections into the 500 kV network. However, the metropolitan areas of Atlanta and Birmingham are excluded from the new proxy generation additions to simulate delivery of power into these major load centers over the bulk transmission network.

For purposes of performing the analysis to determine the increase in power flows on transmission facilities from load growth, the power flow model is utilized to scale the system load in the transmission planning cases by 300 MW for each year of projected load growth. This load scale is performed on a pro-rata basis for the load located at each existing system load bus.

This process is repeated for each year in the 20-year study timeframe until the system load has been scaled by a total of 6,000 MW. The load at each bus is scaled using an assumption that the power factor (pf) of the load does not change as it is scaled.

In order to determine the transmission projects necessary to support 20 years of load growth, the Managing and Utilizing System Transmission ("MUST") power flow transfer analysis tool is utilized on the created cases. MUST simultaneously scales up the proxy generation and forecast load, simulating serving load growth from the proxy generation. The single transmission line (i.e., N-1) contingency analysis performed by MUST is utilized to determine the MW transfer level at which a given transmission facility becomes overloaded. A series of approximately 60 more cases are created with individual existing units modeled offline in order to create generation contingency (i.e., N-G) system models. A similar MUST analysis is run resulting in a single transmission line plus generator contingency (i.e., N-G-1) analysis matching the typical transmission planning expansion criteria. The most limiting system loading from the N-1 and N-G-1 cases are reviewed to determine the need for transmission expansion projects. Each thermal constraint identified through the MUST analysis process is then evaluated on a case-by-case basis to determine the transmission project necessary to alleviate the constraint. The cost of each identified project is determined using planning level cost estimates. The timing of those projects is determined based on the MW transfer level identified for the constraint. The identified MW transfer level is divided by 300 MW load growth per year to determine the expected year of construction for identified projects.

This process is performed with and without the DG to determine the impact that the DG has on the expected timing of the projects. This resulting difference in transmission project timing to serve load over the 20-year study period is evaluated in an economic analysis that results in a cost or benefit that can be attributed to DG.

**Reduced Transmission Losses**

As discussed in the Avoided Energy Cost section above and in Appendix C, the energy component of transmission losses is incorporated into the process for calculating Avoided Energy Costs. The demand component of transmission losses represents the reduction in demand (MW) on the transmission system resulting from a reduction in transmission system losses due to the renewable generation. DG will typically provide transmission capacity loss benefits. However, the utility scale projects connected to the distribution system may be either a transmission capacity loss benefit or cost depending upon the location. This is because the larger scale projects typically feed back into the transmission system and look more like a utility scale generator than distributed generation. Depending upon the location of the larger scale system, this may actually increase losses rather than offset them.

The impact of the demand component of transmission losses is incorporated into the transmission planning studies for Deferred Transmission Investment. The transmission planning models have load represented in the system model at the actual substation location with an amount based on load forecast. The load is distributed among system buses based on historical field measurements of load at each modeled location. DG is studied in the transmission planning models as a reduction in load at specific buses based on the proposed distribution of DG. That reduction in load is then simulated to determine if there is an impact to the transmission expansion plan. As the load is reduced, or displaced in the model by DG, the impact of the load reduction and related transmission system losses is inherently included in the analysis of any change in timing of transmission investment. Therefore, the demand component is recognized as a benefit that is already included in the Deferred Transmission Investment.

**Reduced Distribution Energy Losses**

The methodology used to calculate the Reduced Distribution Energy Losses associated with the addition of DG would be the same as that for Avoided Energy Costs and Deferred Capacity Costs, except the calculation is applied only to the distribution loss profile. Using the same model that is used for the Avoided Energy Costs and the Deferred Capacity Costs, the 8,760-hour (8,784 for leap year) distribution loss profile is applied to the system avoided energy costs and CWFT (see those sections for detailed formulas). The distribution loss profile is developed by multiplying the distribution profile by system-weighted distribution loss factors that include components for transmission substation losses, sub-transmission losses, and distribution system losses. Alternatively, the DG profile can be grossed up by the amount of distribution losses. In this case, the benefit of the Reduced Distribution Energy Losses is incorporated into the calculation of Avoided Energy Costs [and Deferred Generation Capacity Costs].

## Generation Remix

Generation Remix will include both a capital cost component and a production cost component.

The capital cost component of the Generation Remix is determined by modeling the renewable resource in the system mix model[10] and determining the impact on the future build-out of the generation expansion plan.[11] Comparing the capital cost of the future build-out of the case with the renewable resource to the base case should indicate the extent to which the addition of the renewable resource has altered the future mix of the system beyond the simple deferred generation determined by the marginal cost analysis. The "delta" analysis of the two cases – that is, the difference in total capital costs between these cases – reflects the total capital cost impact of adding the renewable, including both the Deferred Generation Capacity Costs associated with the renewable resource and the capital cost impacts associated with Generation Remix. Therefore, to isolate just the Generation Remix capital cost, subtract the previously determined Deferred Generation Capacity Costs associated with the renewable resource as follows:

$$GRC = (SMC_{remix} - SMC_{base}) - DGCC.$$

Where:

$GRC$ = Generation Remix Capital Cost;

$SMC_{base}$ = Capital cost of the future build-out of the system mix base case;

$SMC_{remix}$ = Capital cost of the future build-out of the system mix case with the renewable resource; and

$DGCC$ = Deferred Generation Capacity Costs associated with the renewable resource.

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[10] Currently, The Company uses Strategist for the system mix model. A system mix model is a production cost model that uses dynamic programming techniques to calculate the total capital and operating costs of hundreds of combinations of generating units to determine the proper mix of capacity resources to serve designated loads. The model determines a least cost plan (based on total NPV) of generic expansion resources to add to an existing fleet for the purposes of meeting a Company's load requirements (energy and capacity).

[11] In order to incorporate the renewable profile into both the system mix and production cost models (which assume interconnection at the transmission level), adjustments to the profile may be necessary to account for losses if the interconnection is at a point other than the transmission system (i.e., the profile would be grossed up for distribution losses).

The production cost component of the Generation Remix is determined by modeling the renewable resource, along with the new generation expansion plan from the system mix Generation Remix case, in the Production Cost model.[12] Comparing the production cost of the renewable case to the base case should indicate the extent to which the addition of the renewable resource has altered system production costs beyond the simple Avoided Energy Costs determined by the marginal cost analysis. The “delta” analysis of the two cases – that is, the difference in total production costs between these cases – reflects the total production cost impact of adding the renewable, including both the Avoided Energy Cost associated with the renewable resource and the production cost impacts associated with Generation Remix. To isolate just the Generation Remix, subtract the previously calculated Avoided Energy Cost savings associated with the renewable resource as follows:

$$GRP = (SPC_{remix} - SPC_{base}) - AEC.$$

Where:

$GRP$ = Generation Remix Production Cost;

$SPC_{base}$ = System production cost of the base case;

$SPC_{remix}$ = System production cost of the case with the renewable resource and modified expansion plan; and

$AEC$ = Avoided Energy Cost associated with the renewable resource.

Total Generation Remix is then the sum of the Generation Remix capital costs and the Generation Remix production costs. Generation Remix can either be a cost or a benefit depending upon the outcome of the above calculations.

**Ancillary Services – Reactive Supply and Voltage Control**

At this time, Southern Company has not developed a methodology to calculate the cost impacts that solar generation has on Reactive Supply and Voltage Control.

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[12] The Production Cost case is developed using the Production Cost model used by Southern Company for development of their official Energy Budget. The Production Cost model performs a detailed 8,760-hour unit commitment and dispatch simulation to calculate these production costs and avoided energy costs.

## Ancillary Services – Regulation

In order to maintain Area Control Error ("ACE") within NERC required limits, the intermittent nature of VERs must be managed through the use of Regulating Reserves. NERC Standard BAL-001[13] specifies these requirements, which include regulating the system to within specified ACE tolerances in a 1-minute interval over a rolling 12-month period and for at least 90% of 10-minute windows in a given month and not exceeding prescribed limits for more than 30 consecutive clock minutes. Respectively, these metrics are Control Performance Standard 1 ("CPS1") and Balancing Authority ACE Limits ("BAAL"). With the current generation mix, the Company has not identified a need to immediately address potential CPS1 issues, but as the penetration of intermittent resources increases, resources to meet the 1-minute requirement may be considered.

The intermittency of renewable generation within the 10-minute Regulating Reserve window has the potential to increase the amount of Regulating Reserves. This is due to the operating characteristics of generating resources on Automatic Generation Control ("AGC"), which are required to respond in order to balance the system's supply and demand while managing renewable intermittency. Therefore, generation resources on AGC dispatched because of the renewable intermittency would not be available to respond to load variability as they would otherwise, thereby increasing the need for additional Regulating Reserves. There are immediate production cost impacts associated with maintaining these additionally required Regulating Reserves, and to the extent the need for these additional Regulating Reserves may impact system reliability, it could eventually result in a capacity need (as determined below in the Support Capacity section). If the need is driven more by CPS1 requirements, resources such as battery energy storage systems capable of responding within a minute may become necessary. The amount of additional Regulating Reserves needed can be determined by evaluating the 10-minute "ramp down" volatility of the renewable resources.[14] An amount equal to the 95$^{th}$ percentile of these 10-minute ramps protects against potential violations of the requirement set by the NERC Standard BAL-001 and provides a reasonable estimate of the additional Regulating Reserves that will ultimately be required as a result of the renewable resource. The cost impacts associated with these additional reserves should be determined according to the Support Capacity calculations specified below.

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[13] http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf

[14] Only the "ramp down" occurrences are considered because only these occurrences contributed to the "Reg Up" Regulating Reserve requirement.

## Support Capacity

Appendix D contains a detailed explanation of the need for and causes of Support Capacity along with an overview for how to determine the amount of Support Capacity to be evaluated. This amount (as specified in Appendix D) is determined by calculating the sum of the aggregate incremental needs of:

(a) The incremental Regulating Reserve requirement and its impact on reliability risk;
(b) The incremental renewable forecast error on reliability risk; and
(c) Any incremental generation ramp requirement.[15]

The addition of these Support Capacity requirements results in both a capital cost and an associated production cost for each of the three types of capacity additions.

To determine the Support Capacity capital costs, these additions, in aggregate, should be modeled in the system mix model as a reduction in the modeled ICE factor of the renewable resources and a "delta" case comparison of the capital costs of the resulting future build should be made against the Generation Remix case. The resulting difference in capital costs of the two cases is the Support Capacity capital cost, calculated as follows:

$$SCC = (SMC_{support} - SMC_{remix}).$$

Where:

$SCC$ = Support Capacity Capital Cost;

$SMC_{support}$ = Capital cost of the future build-out of the system mix base case with the additional support capacity requirements; and

$SMC_{remix}$ = Capital cost of the future build-out of the Generation Remix system mix case.

To determine the Support Capacity production costs, a Production Cost model case is developed using the Generation Remix Production Cost case as a base. That case is modified to include the expansion plan from the Support Capacity system mix case, but also includes the

[15] At this time, Southern Company has not developed an agreed-upon methodology for determining the ramping requirements of a significant penetration of renewable resources.

modeling of the additional Regulating Reserve requirements to capture the production costs associated with those requirements. Regarding the production cost associated with forecast errors, given the expectation of the mean-reverting nature of the renewable forecasting process, the forecast error production costs have been assumed to be zero (0) for purposes of this Framework.[16] The production cost of this case is then compared against the production cost of the Generation Remix case to determine the Support Capacity Production Costs as follows:

$$SCP = (SPC_{support} – SPC_{remix}) \ .$$

Where:

$SCP$ = Support Capacity Production Cost;

$SPC_{support}$ = System production cost of the Support Capacity case; and

$SPC_{remix}$ = System production cost of the Generation Remix case.

Total Support Capacity Costs is then the sum of the Support Capacity Capital Costs and the Support Capacity Production Costs.

**Bottom Out Costs**

At this time, Southern Company has not developed an agreed-upon methodology to calculate the expected Bottom Out Costs associated with significant penetrations of renewable resources.

**Long-Term Service Agreement Costs**

At this time, Southern Company has not developed a methodology to calculate the expected LTSA costs associated with significant penetrations of renewable resources.

**Distribution Operating Costs**

[16] This assumption is based on the premise that a perfectly unbiased mean-reverting forecasting methodology would, over time, always converge back such that the net production cost impact of the forecast error is zero or negligible. In reality, forecasting biases as well as temporal differences in production cost would result in a relatively small but non-zero net production cost impact associated with the forecast errors. The Framework provides for the fact that if such can be determined, then these costs can be properly included.

At this time, Southern Company has not developed a methodology to calculate the expected Distribution Operating Costs associated with significant penetrations of renewable resources.

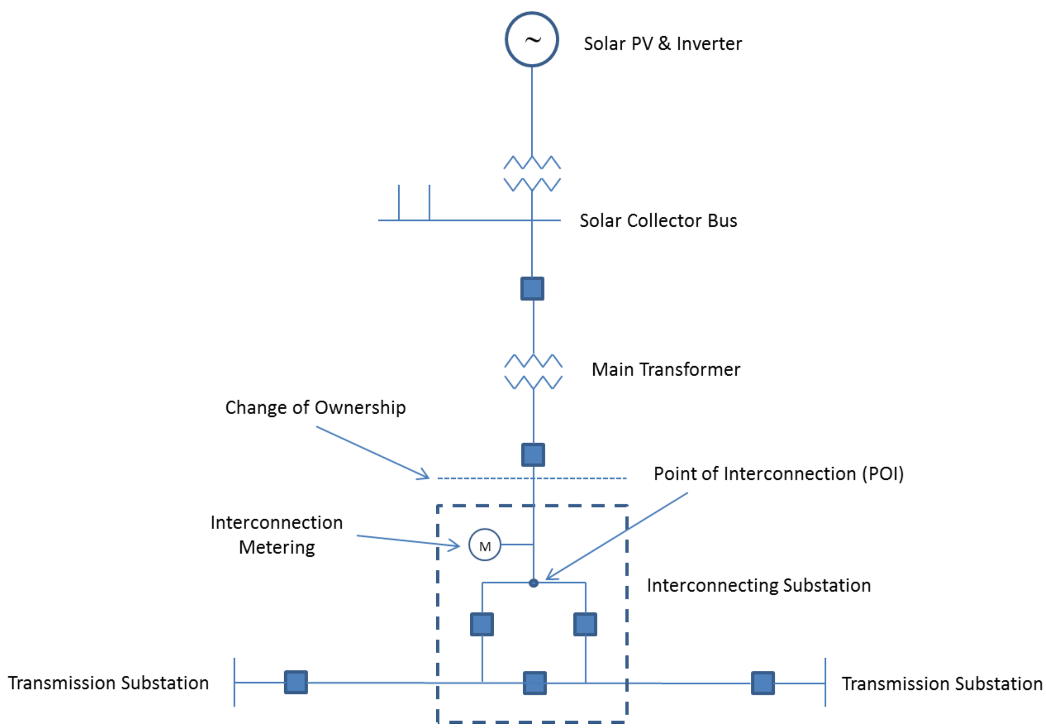
**Program and Administrative Costs**

At this time, Southern Company has not developed a methodology to calculate the expected Program and Administrative Costs associated with significant penetrations of renewable resources.

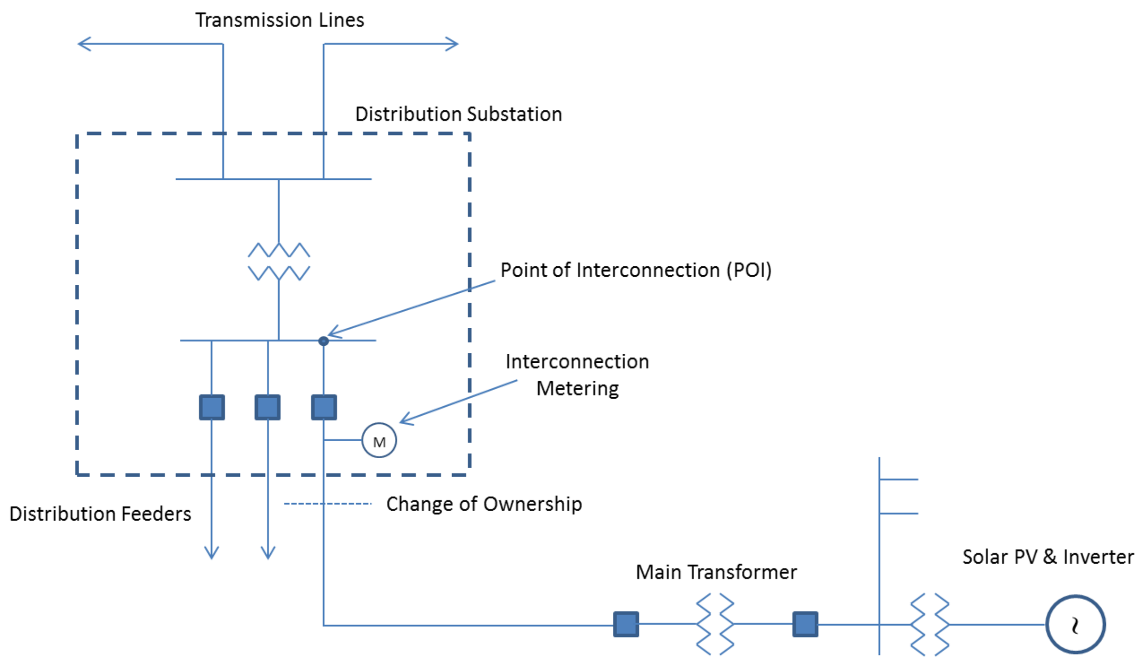
## APPENDIX A – REFERENCE CONNECTIONS

The various connection types shown are for illustrative purposes only. For Utility Scale – Transmission (US-T), Utility Scale – Distribution (US-D), and Distributed – Greenfield (DG-G), the exact interconnection configuration will be determined by the respective Operating Company.

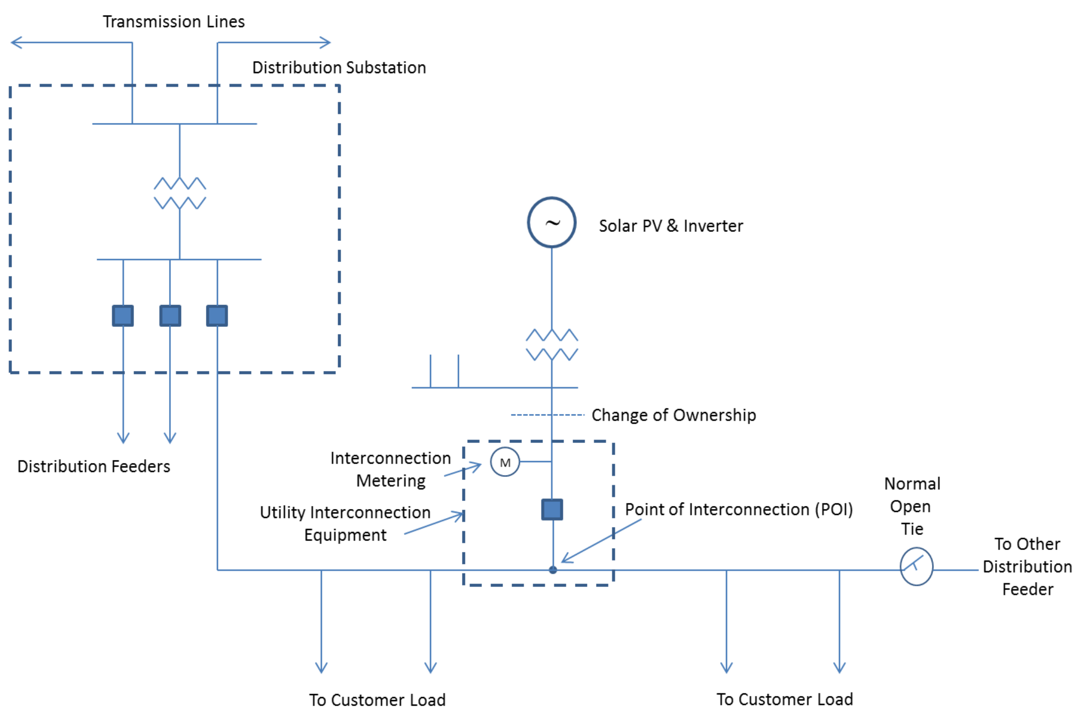
### Utility Scale – Transmission (US-T)



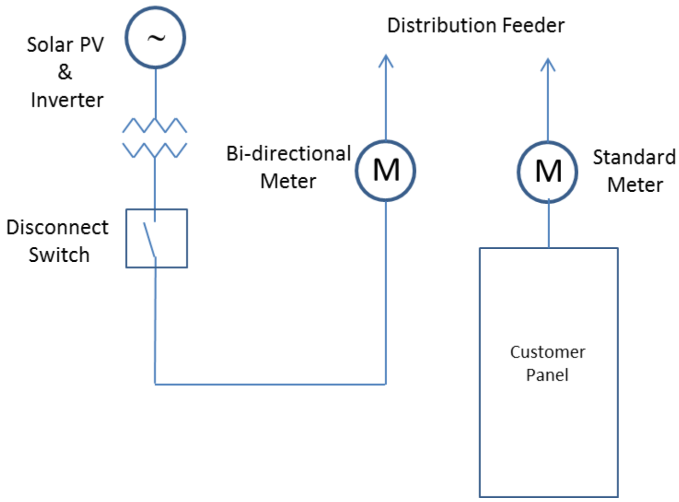
## Utility Scale – Distribution (US-D)



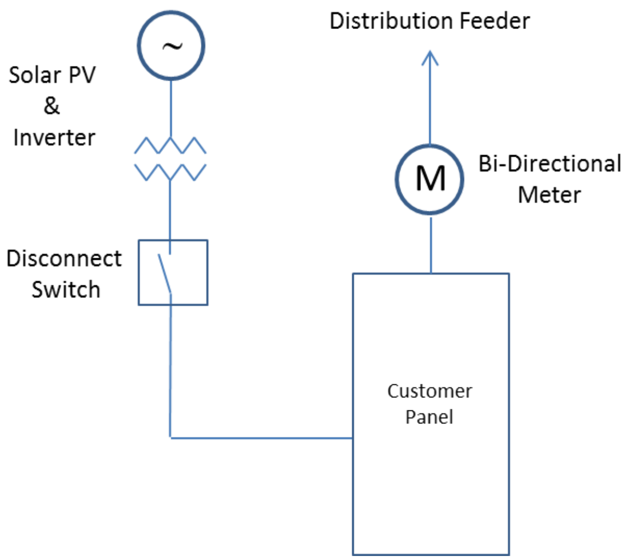

## Distributed – Greenfield (DG-G)



### Distributed – Metered (DG-M)




### Distributed – Behind the Meter (DG-BTM)



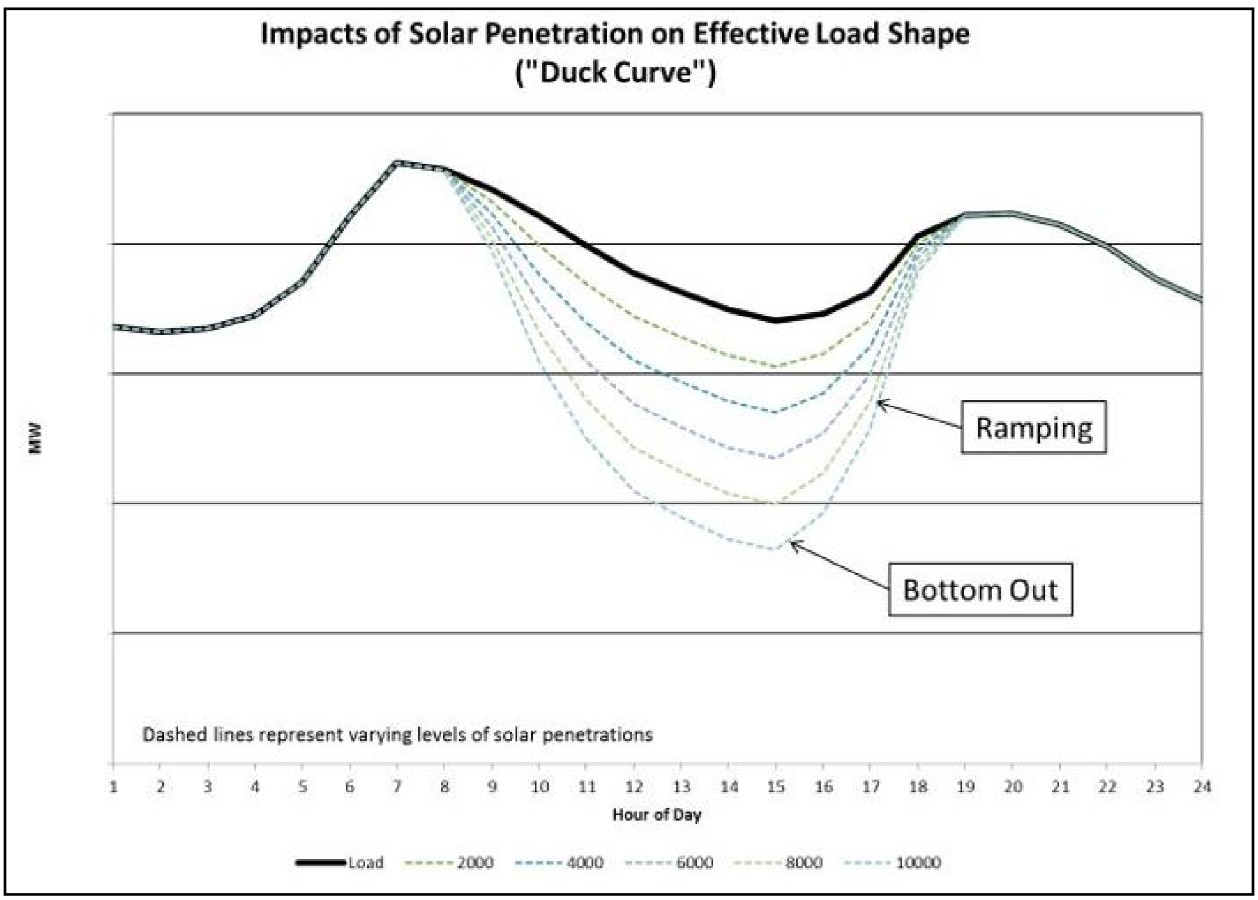
## APPENDIX B – IMPACTS OF RENEWABLE GENERATION ON EFFECTIVE SYSTEM DEMAND

It has been widely publicized in the electric industry that significant penetrations of renewable resources can have detrimental impacts on the generation ramping requirements of the system. For example, while solar is a resource and not a "negative" demand, solar generation is non-dispatchable and therefore has an impact on the residual load to be served by the remaining, dispatchable resources. There are two significant impacts that large penetrations of solar can have on this effective system demand. The first is the "duck curve" phenomenon and the second is a shift of summer peak demand (i.e., "peak shift") from afternoon into post-dusk evening.

## The Duck Curve Impact

Solar facilities produce electricity only during daylight hours. Large penetrations of solar will result in significant ramping up of solar generation at dawn. Likewise, there will also be a ramping down of solar generation at dusk. In the winter time, load is typically reaching its daily peak just prior to or shortly after dawn, ramps down during the midday hours, and then ramps up again in the evening, creating a double-peak effect to the load shape. This means that solar generation is ramping up as load is ramping down on winter mornings and solar generation is ramping down as load is ramping up on winter evenings. The net effect is an exaggerated midday low in the effective system demand, which can exacerbate that which is often already a difficult generation ramping condition. This effect, demonstrated in Figure B-1 below, has been referred to as the "duck curve" in the industry due to the shape of the resulting effective generation ramp resembling a duck.

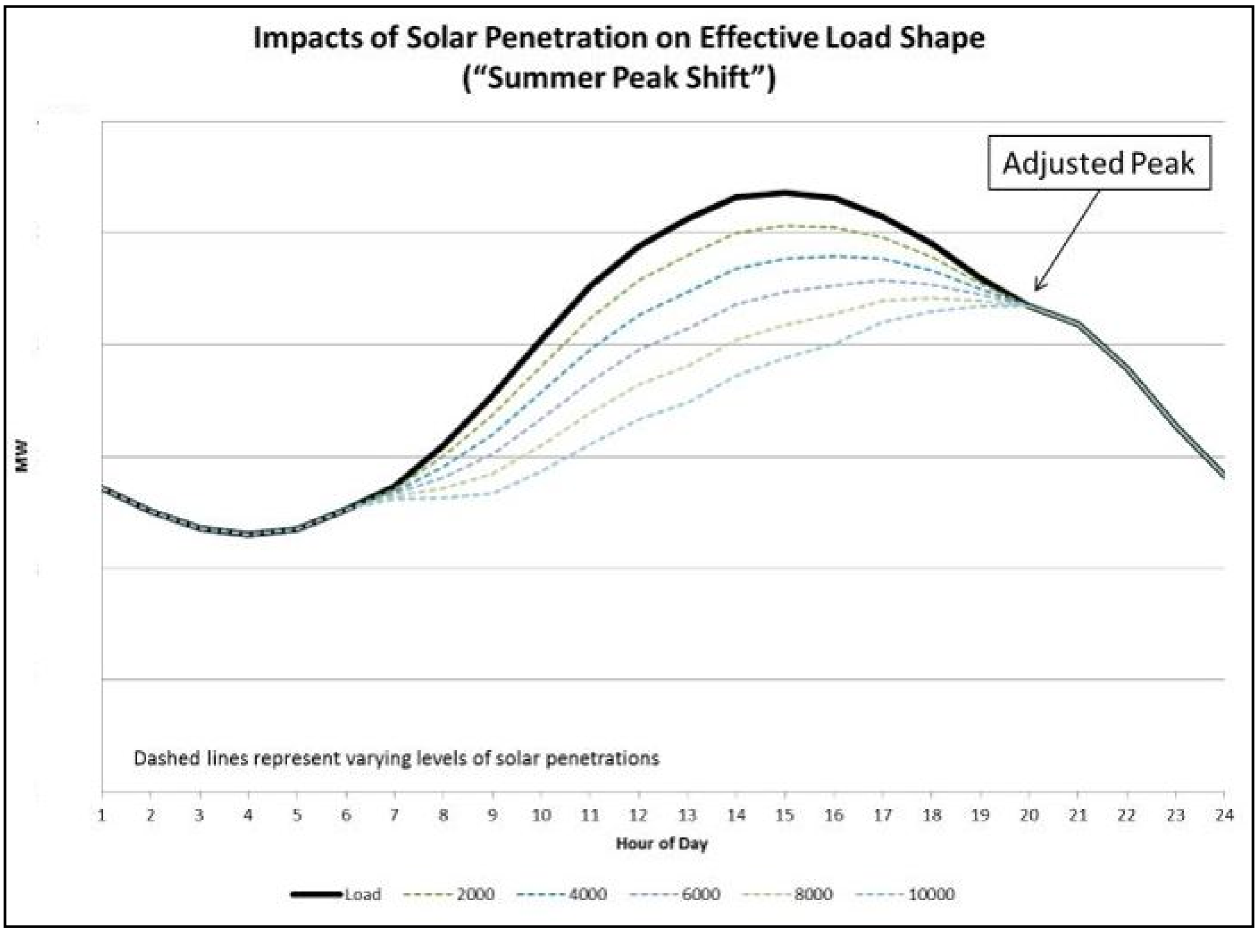
**Figure B-1. Impacts of Solar Generation on Winter Effective System Demand**



## The Peak Shift Impact

In the summer, load is ramping up in the morning and ramping down in the evening. As such, solar has the effect of shaving the peak of the effective system demand. As more solar generation is added to the system, the effective system demand is lowered. However, because solar begins ramping down at dusk, solar can never lower the effective summer peak demand below the demand point immediately after sunset. With sufficient penetrations of solar, the effective summer peak demand will therefore shift from late afternoon to immediately after sunset as demonstrated in Figure B-2 below.

**Figure B-2. Impacts of Solar on Effective Summer Peak Demand**



## APPENDIX C – SYSTEM AVOIDED COSTS

Southern Company makes avoided energy cost projections based on a scenario planning process. In this process, Southern Company works with external consultants to develop a set of scenarios that reflect uncertainties relevant to the continuous need to serve customers reliably and in a cost-effective manner, and the numerous decisions associated with that service. The scenarios analyzed consider variations to modeling inputs, such as changes in assumptions associated with forecasted fuel and carbon allowance prices, along with overall energy demand developed using a macro-economic model. Products of these scenarios also reflect expansion, retirement, and retrofit plans for Southern Company's generating fleet. These plans are used in conjunction with the modeling inputs to produce avoided energy costs for every scenario.

Avoided energy cost projections are developed using the Production Cost model. The Production Cost model is a complete electric utility/regional pool analysis and accounting system that is designed for performing planning and operational studies. It is an hourly production cost model that has the fundamental goal of minimizing total production cost while providing detailed projections of fuel cost and pool accounting, including individual unit information. Inputs into the Production Cost model include scenario-specific information such as load forecasts, fuel price forecasts, fleet expansion plans, and emissions allowance prices. Other inputs that do not necessarily change across scenarios are transmission constraints, economic energy purchases and sales, nuclear and hydro budgets, and unit characteristics (heat rates, emission rates, VOM, max/min capacities, outage schedules, etc.).

The Avoided Energy Cost, or marginal cost, is the dispatch cost of serving the next kWh. Avoided energy costs are determined every hour and represent the cost to produce the next increment of electrical power to meet Southern Company's total load. As the first derivative of the production cost equation, the dispatch cost equation includes these components: incremental heat rate; marginal replacement fuel; emissions; VOM; fuel handling; and transmission penalty factor (transmission energy losses). These components are described in detail below.

**Incremental heat rate:** This is the heat input required to increase energy output by 1kW. Heat rate coefficients required to calculate a unit's incremental heat rate are provided by Southern Company's generating plants from historical testing, and coal units are monitored monthly based on 12-month rolling average actuals.

**Marginal replacement fuel:** This is the cost of supplying additional fuel to the plant. Marginal delivered fuel forecasts are based on short-term and long-term forecasts developed in the scenario planning process.

**Emissions:** This is the replacement cost of allowances to emit $SO_2$ and/or NOx when burning the next Btu of fuel. Allowance price forecasts are based on market data regarding the allowances collected during the scenario planning process.

**Variable operations & maintenance:** This is the variable cost of maintenance required to obtain an additional MW over one hour for a specific generating unit. VOM forecasts are developed using budgeted VOM dollars from FERC-specified accounts provided by the Operating Companies.

**Fuel handling:** This is the variable cost of in-plant fuel handling required to obtain an additional MW over one hour for a specific generating unit. Fuel handling forecasts are developed using the same methodology as VOM except that fuel handling is received as a separate line item in budgeted dollars from the Operating Companies. These accounts are also FERC-defined.

**Transmission penalty factor ("TPF"):** This is a location dependent multiplication factor that is applied to the marginal cost to account for the loss of energy during transmission from the generator to bulk transmission levels. TPFs are unit specific multipliers based on average historical data that represent the change in generating cost that occurs when going from the generator to the load center.

## APPENDIX D – SUPPORT CAPACITY

### The Need for Support Capacity

The purpose of this appendix is to provide a description of the need for and method of determining Support Capacity associated with the implementation of VERs on the electric grid. The Company has identified a number of costs associated with significant penetrations of VERs. These costs are real costs that are a direct result of VERs and not attributable to traditional, dispatchable resources.

It has been widely acknowledged that VERs may require some form of "backup" capacity to firm those resources during periods of time when they are not operating. The hourly integrated expected output from these resources varies from hour-to-hour and from year-to-year depending upon the weather. In its planning processes, Southern Company views this "backup" capacity not in terms of a cost adder but rather in terms of de-rating a VER's nominal capacity to its Incremental Capacity Equivalent. However, in addition to this capacity equivalency, there is still the need for additional adjustments to this ICE factor that are necessary to account for the other aspects of the intermittent nature of the VERs. This intermittent nature has a negative impact on system reliability (as described below) that can be mitigated through the addition of resources. For planning purposes, these intermittency impacts are reflected in a reduction in the ICE factor of the renewable resource. This adjusted ICE factor ultimately results in the need for more capacity than would otherwise be assumed using the unadjusted ICE factor. Additionally, the intermittent nature of VERs creates a need for additional flexible resources in the operational horizon (as described below) to account for ramping requirements. It is possible that at significant enough penetrations of VERs, it may become necessary to add generation resources solely to meet this flexible resource requirement. These flexible resources would be those resources (such as CTs, hydro, etc.) that are capable of being committed and fully dispatched within a 30-60 minute timeframe. The Support Capacity concept is also used to capture all of these requirements.

Based on the above, Support Capacity needs are caused by (a) the reliability impacts associated with the additional Regulating Reserve requirements necessary to handle moment to moment swings in VER output, (b) the reliability impacts associated with VER forecasting errors, and (c) increased generation ramping/load following requirements caused by VERs.

**Regulating Reserves:** Although VER output is not considered "load" *per se*, because VERs are not dispatchable, the output of VERs has an "effective" result on the economic dispatch ramping requirements of the remaining generation fleet. As the output of VERs fluctuate (e.g., as clouds pass over solar resources or as wind starts/stops blowing), other dispatchable resources must adjust to account for these fluctuations. This affects the generation fleet as if it were a fluctuation in load. Because many of these fluctuations occur over a short period of time (i.e., seconds to minutes), these moment to moment swings in the generation ramping requirements must be managed by Regulating Reserves in order to maintain compliance with NERC balancing requirements. To ensure those NERC requirements are met, this need must be met by a resource that is on AGC and capable of ramping in 10 minutes. When a VER resource experiences a reduction in output over a 10-minute period (i.e., a "ramp down" condition), it results in the need for Regulating Reserves to ramp up. Assuming no definitive correlation between load volatility and VER volatility, it must be assumed that these fluctuations are additive in nature, resulting in a need for additional Regulating Reserves than would otherwise be required. This additional requirement would be necessary in all hours that the VER is expected to operate. However, when determining the impact of this additional requirement on system reliability, only those hours in which there is a reliability risk should be considered. This ensures that only those hours that are reliability constrained are considered in determining the capital cost impact of the incremental Regulating Reserve requirement.

**VER Forecast Errors:** Because VERs are not dispatchable, there is a need to forecast the expected output of the VERs to be able to properly plan for and operate the system. To the extent the actual output of the VERs differs from the forecasted output of the VERs, other resources will have to make up the difference. The timeframe in which these forecast error effects are manifested is typically in the 30-60 minute window, which also creates a need for generation response from existing online and available resources, furthering the need for flexible resources. In the case where this error is the result of an over forecast (i.e., more output was forecasted than was actually generated), this can create a reliability concern, particularly if it occurs in an hour where there is already a reliability risk.

**Generation Ramping/Load Following:** Finally, in many cases (such as when solar resources stop generating at sunset), these fluctuations in VER output can result in increased generation ramping (i.e., load following) requirements for the remaining dispatchable resources on the system. These changes in the generation ramping requirements can occur in multiple timeframes from minutes to hours. Initially, these fluctuations will be managed and served by online and available resources (i.e., Contingency Reserves). However, to maintain compliance with NERC Contingency Reserve requirements, these Contingency Reserves must be replaced within a short period of time, thus creating a need for flexible resources.

## The Determination of Support Capacity Requirements

Generally speaking and assuming the system has enough flexible resources to handle the total Support Capacity requirements, Support Capacity can be used to serve double duty – that is, provide both load-serving capability as well as meeting flexibility requirements. However, there are three exceptions.

First, Support Capacity that is required to provide incremental Regulating Reserves at any given time cannot also serve load at the same time. Otherwise, it would not be available for providing regulation to the system. Therefore, any incremental Regulating Reserve requirement associated with the VER must be properly accounted for as a capacity reserve obligation in the planning process. However, to the extent the addition of the renewable resource may have offset other generating capacity, that capacity may be used to meet the Regulating Reserve requirement. Therefore, to determine the reliability impact of the incremental Regulating Reserve requirement, an hourly Regulating Reserve requirement profile can be developed and multiplied each hour by the CWFT. The CWFT identifies the relative reliability risk in each hour and so would discount or eliminate the impacts of those hours in which the reliability risk is reduced or non-existent.

To develop this Regulating Reserve requirement, a sufficient amount of historical or simulated 10-minute ramp information for the renewable resource is necessary. This information is first reduced so that only the "ramp down" instances are considered. From the remaining data, the 95$^{th}$ percentile of all ramp down instances determines the total Regulating Reserve requirement (for production cost purposes). However, to determine the reliability impact (for capital cost purposes), the 95$^{th}$ percentile of the ramp down instances are determined ***for each hour*** of the year. This produces an hourly Regulating Reserve requirement profile that can then be multiplied by the CWFT as follows:

$$VER_{RR} = [\ ]$$

Where:

$VER_{RR}$ = the VER Regulating Reserve reliability impact (in % of nominal VER capacity);
*CWFT (i)* = the Capacity Worth Factor for hour *i* in any given year (measured in %); and
*VRR(i)* = the expected VER Regulating Reserve requirement in hour *i* (measured in % of nominal VER capacity).

If necessary, a MW impact can be determined by multiplying this requirement by the nominal capacity of the VER resource.

Second, as with Regulating Reserves, Support Capacity needed to account for VER forecast error likewise cannot serve planned load. Otherwise, it would not be available to make up any differences associated with VER forecast error. However, there are many hours in which there is sufficient existing capability on the system to handle this forecast error. As with Regulating Reserves, only the impact of forecast error in those hours in which there is a reliability risk should be considered. To determine the reliability impact associated with VER forecast error, therefore, sufficient historical or simulated forecast error data is necessary so that an hourly VER forecast error profile can be developed. Because only those instances in which the forecast error reflects an over forecast create a potential reliability risk, the dataset is first reduced by eliminating the under forecasted instances. From the remaining dataset, an hourly VER forecast error profile is developed that appropriately reflects the Company's risk tolerance related to VER forecast error.[17] This VER forecast error profile can then be multiplied by the CWFT to determine the impact that VER forecast error has on system reliability as follows:

[17] This profile is developed based upon a risk tolerance that reflects the 68$^{th}$ percentile (i.e., one standard of deviation) of the over forecasted instances in each hour.

$$VER_{FE} = [\ ]$$

Where:

$VER_{FE}$ = the VER Forecast Error reliability impact (in % of nominal VER capacity);
*CWFT (i)* = the Capacity Worth Factor for hour *i* in any given year (measured in %); and
*VFE(i)* = the expected VER Forecast Error in hour *i* (measured in % of nominal VER capacity).

If necessary, a MW impact can be determined by multiplying this requirement by the nominal capacity of the VER resource.

Third, Support Capacity that is required to provide incremental generation ramp requirements cannot also serve load at the same time. However, as noted above in Section 4, at this time Southern Company does not have an agreed-upon methodology for determining the Support Capacity impacts associated with ramping.

Therefore, the total reliability impact of the Support Capacity requirement is equal to the sum of the incremental Regulating Requirement reliability impact plus the VER forecast error reliability impact. In other words:

$$SC_{Inc} = VER_{RR} + VER_{FE}$$

This amount (in % of nominal VER capacity), represents the total adjustment necessary to the VER ICE factor to account for the intermittent reliability risk.

The capital and production costs associated with this Support Capacity requirement is determined as specified in Section 3 of this Framework.

## APPENDIX E – DATA EXTRAPOLATION

Given the varying term lengths in which data is available, instances occur where data must be extrapolated within the 30-year period covered by the RCB Framework. In addition, when the RCB Framework is applied to Power Purchase Agreements ("PPA") that extend beyond 30 years, extrapolation techniques must be utilized.

One such example of extrapolation occurring within the RCB Framework can be seen in the development of the Deferred Transmission Investment component values. The underlying transmission planning study covers a period of 20 years. Pursuant to the Joint Recommendation, the average of the value of the annual ECC of the change in transmission investment for the last 10 years of the study period will be calculated and serve as the value for the year following the end of the transmission planning study period. That average value will then be escalated at the Company's Transmission Capital Cost Escalator, which is base inflation, for the remaining years of the period covered by the RCB Framework.

Regarding cases where the RCB Framework is applied to data beyond the coverage period of the RCB Framework, standard escalation techniques, such as applying growth rates over the study period, will be utilized. A recent example of the need for this type of extrapolation was when the RCB Framework was employed in the evaluation of the bids received in response to Georgia Power's REDI DG RFP, which accepted bids with PPA terms of up to 35 years.