**The Costs and Benefits of Distributed Solar**

**Generation in Georgia**

**Draft: 01/25/16**

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**SECTION 1 – EXECUTIVE SUMMARY**

**Introduction**

The purpose of this document is to present the results of an analysis to determine the impacts of various levels of distributed solar penetration in Georgia. Neither this analysis nor the performance of it represents a view that such levels of penetration are either possible or anticipated. Rather, the purpose of this analysis is to develop a general expectation regarding the costs and benefits of distributed solar in Georgia and to assess the extent to which various levels of penetration of distributed solar will impact the operation of the electric system in Georgia.

**Process and General Approach**

This analysis of the costs and benefits of distributed solar was performed according to the processes and methodologies described in the document titled “A Framework for Determining The Costs and Benefits of Solar Generation in Georgia” (“Framework”).

Because many aspects of the costs and benefits realized by distributed solar are dependent upon the level of penetration, an iterative approach to evaluating the costs and benefits is appropriate. The iterative approach used for this analysis was based on incremental distributed solar penetrations in eight 1000MWAC tranches (solar blocks), with each subsequent 1000MW tranche building upon the results of the previous 1000MW tranche. For example, the first 1000MW tranche is evaluated assuming that solar block is added to the existing planning cases.[[1]](#footnote-1) Each additional 1000MW tranche would be added and evaluated incrementally to the results of the final analysis of the previous tranche. Each tranche evaluated, therefore, would reflect the incremental costs and benefits over the previous tranche.

Because the goal is to determine the types of impacts that may be caused by increasing levels of distributed solar penetration, it was assumed that all of these 1000MW tranches could be implemented overnight. While practically infeasible, utilizing this approach gives a clearer comparative picture as to the differences among the 1000MW tranches.

**Summary of Results**

Table 1 contains a summary of the results of the cost-benefit analysis of Distributed-Metered (DG-M) and Distributed-Behind the Meter (DG-BM)[[2]](#footnote-2) solar generation for each of the eight 1000MW distributed solar tranches. The results[[3]](#footnote-3) shown in Table 1 are levelized[[4]](#footnote-4) across 30 years beginning in 2019. The value shown in each category for each tranche is incremental to the previous tranche and represents the benefit or cost of an additional 1000MW of distributed solar to the Georgia Power Electric System after considering the impact of the previous 1000MW of distributed solar. The installation costs of the distributed solar facilities are ***not*** included in this analysis.

**Table 1: Levelized Costs and Benefits of Distributed Solar Generation ($/MWH)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Tranche Size | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Avoided Energy Costs | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Deferred Generation Capacity Costs | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Deferred Transmission Investment | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Reduced Distribution Losses | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Distribution Operations Costs |  |  |  |  |  |  |  |  |
| Ancillary Services - Reactive Supply and Voltage Control |  |  |  |  |  |  |  |  |
| Generation Remix Costs | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Support Capacity (Flexible Reserves) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Bottom Out Costs | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Long Term Service Agreement (LTSA) Maintenance Costs |  |  |  |  |  |  |  |  |
| Target Reserve Margin Costs |  |  |  |  |  |  |  |  |
| Program and Administration Costs |  |  |  |  |  |  |  |  |
| Total Net Avoided Cost | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Figure 1 provides a pictorial representation of the results shown in Table 1.

**Figure 1: Levelized Costs and Benefits of Distributed Solar Generation ($/MWH)**

|  |
| --- |
| **REDACTED** |

Because this particular analysis was developed to show costs and benefits in levelized format, these results are for comparison purposes only to show relative impacts of various levels of ***sustained*** distributed solar generation. Figure 2 provides various levelized terms for the first 1000MW tranche to illustrate benefit and cost impacts for 5, 10, 15, 20, 25, and 30-year terms. They should not be used to infer any specific value of distributed solar generation in any particular year, and should not be used to price any particular distributed solar program. Should there be a need to develop such pricing mechanisms, an analysis should be performed using consistent Framework methodologies and project-specific details and assumptions.

**Figure 2: Levelized Costs and Benefits of Distributed Solar Generation – 1000MW Tranche ($/MWH)**

|  |
| --- |
| **REDACTED** |

**Conclusions**

A number of conclusions can be drawn from these results. As a reminder, however, because of how these specific results were calculated and the assumptions used in calculating them, one conclusion that ***should not*** be made from these results is that solar can/should be added on the system at rates derived from these particular solar cost benefit results. These results are based on a number of assumptions that were made for the purpose of determining the relative impacts of increasing penetrations of solar on the system and not for the purpose of determining costs and benefits for any particular project or program. Any specific solar project or program should be evaluated in a similar manner using the Framework and the appropriate assumptions associated with that program or project.

Conclusions that ***can*** be drawn from these results include the following important observations:

1. The total benefit provided by solar generation exceeds the total cost caused by solar generation; however, with increasing penetration levels the overall benefit to the system declines.
2. On average (after the 2000MW tranche and excluding the 8000MW tranche which represents a substantial cost breakpoint), the decline in the total avoided cost of solar amounts to roughly **REDACTED** for each 1000 MW of solar installed on the system (i.e., each 1000 MW of distributed solar installed – up to 7000MW - is worth about **REDACTED** less than the previous 1000 MW installed).
3. Total avoided costs remain fairly stable up through 2000MW of distributed solar, after which the costs tend to decline steadily until the next big cost breakpoint at 7000MW of distributed solar – the point at which there is no longer a deferred generation capacity and deferred transmission investment benefit from distributed solar due to the time shift of the peak to dusk.
4. Compared to the avoided energy benefits provided by distributed solar, the deferred transmission investment benefits are extremely small on a relative basis.
5. Costs associated with Support Capacity and Generation Remix are immediately incurred with low penetrations of solar.
6. Even with perfect knowledge and perfect confidence in the expected solar profile, the system reaches a point between 4000 and 5000 MW of distributed solar in which it can no longer recommit to avoid bottom out conditions; although the costs are estimated to be relatively low (as calculated here using avoided energy cost as a proxy for over generation costs), it can be assumed that this increase in bottom out conditions represents a significant increase in the operational challenges associated with solar generation.

Based on these conclusions, all new proposed solar resources should be evaluated in light of all previously committed solar projects so that the declining value of solar generation can be appropriately measured. Based on today’s view of the future, it can also be concluded that due to the breakpoints in operational costs associated with solar and the potential for significant increases in operational problems at these levels, consideration of solar penetrations in the 4000-5000 MW range could create the need for mitigation measures. Although this study was performed for distributed solar generation, the general conclusions are applicable to all solar generation added to the system, including utility scale solar generation.

**SECTION 2 – DISTRIBUTED SOLAR COST-BENEFIT RESULTS**

**Distributed Solar Hourly Profiles**

The starting point of this analysis was the determination of the expected distributed solar profile. The determination of this hourly solar profile is highly dependent upon a number of solar configuration and meteorological assumptions. These configurations and assumptions can vary significantly from project to project and, for purposes of anticipating future projects, are impossible to predict. Therefore, a number of assumptions were made in an attempt to generate a reasonable set of distributed solar generation profiles.

For meteorological assumptions, Typical GHI (Global Horizontal Irradiance) weather from the NREL (National Renewable Energy Laboratories) Solar Prospector website[[5]](#footnote-5) was used. This assumption was based upon the fact that the Typical GHI meteorological data is specifically designed to create a set of profiles that approximates on a monthly basis the average output that would have been produced over the course of a series of historical years.

The solar configuration assumptions used for this analysis included assumptions for the following:

1. A breakdown of the distribution of solar generation across the system;
2. A breakdown of the assumed DC-AC ratios for each location;
3. A breakdown of the assumed Azimuth settings for each location; and
4. A breakdown of the assumed Tilt settings for each location.

With respect to the distribution of solar resources, it was assumed that the solar resources were distributed somewhat proportionally to the major load centers across the Georgia Power Electric System. The geographic diversity of solar was therefore assumed as shown in Table 2 below.

**Table 2: Distributed Solar Diversity Assumptions**

|  |  |
| --- | --- |
| Regional Allocations | By Region |
| Atlanta | 63% |
| Columbus | 9% |
| Macon | 10% |
| Augusta | 7% |
| Albany/Valdosta | 11% |
| Total | **100%** |

Applying these allocation factors to each of the 1000MW tranches of distributed solar results in the modeling assumptions shown in Table 3 below.

**Table 3: Distributed Solar Assumptions for GPC (MW AC)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| GPC | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Atlanta | 630 | 1260 | 1890 | 2520 | 3150 | 3780 | 4410 | 5040 |
| Columbus | 90 | 180 | 270 | 360 | 450 | 540 | 630 | 720 |
| Macon | 100 | 200 | 300 | 400 | 500 | 600 | 700 | 800 |
| Augusta | 70 | 140 | 210 | 280 | 350 | 420 | 490 | 560 |
| Albany/Valdosta | 110 | 220 | 330 | 440 | 550 | 660 | 770 | 880 |
| **Total** | **1000** | **2000** | **3000** | **4000** | **5000** | **6000** | **7000** | **8000** |

Knowledge of DC-AC Ratios, Tilt, and Azimuth configurations are vitally important to this analysis because they each can affect the assumed profile and, therefore, they all can affect the avoided energy and deferred capacity benefits associated with distributed solar. Given the numerous variations presented by these configurations, it was determined that a generalized assumption based on reasonable values would be the most appropriate approach for these variables.

For DC-AC Ratios, a general assumption of 1.2 was made based on a review of typical distribution solar installations.

Because it can be anticipated that distributed solar resources will be comprised primarily (if not almost exclusively) of rooftop residential and commercial installations, it was assumed that none of the distributed resources would be implemented using single or dual axis tracking technology. Therefore, assumptions for Tilt and Azimuth associated with fixed axis implementation were established as follows:

* For Tilt, it was noted that commercial PV installed on flat roofs are often in the 10-15% (relative to horizontal) tilt range, while residential rooftops can have pitches ranging from 4/12 to 12/12, corresponding to tilts in the range of 18 to 45 degrees. For an aggregate assumption, 20% tilt on average was used.
* For Azimuth, it was presumed that PV installations would trend towards south facing, but that actual orientation would often be limited based on the actual available architecture. Therefore, it was assumed that there would be a wide range of implementations facing generally in the southern direction: 1/3 of the installations would face southwest; 1/3 would face south; and 1/3 would face southeast.

To account for degradation of solar panels over time, a degradation factor of 0.5% per year was assumed and applied to the aggregate hourly-distributed solar profile.

In total, the above combinations of assumptions result in 15 streams of hourly solar profiles for each 1000MW solar tranche. These profiles were developed using the PVSyst solar profile modeling application and were weighted into an aggregate system-wide distributed solar hourly generation profile. Arithmetically, this aggregate profile produces the same results as looking at each profile individually. Table 4 below depicts a monthly representation of the aggregate expected hourly output of these distributed solar tranches as a percentage of nominal installed (AC) capacity.

**Table 4: Aggregate Expected Distributed Solar Profile as a Percentage of Installed Capacity**

|  |
| --- |
| **REDACTED** |

**Avoided Energy Costs**

In accord with the Framework, the avoided costs used in this analysis are the official avoided costs for the Southern Company electric system. For this analysis, therefore, the B2016 Moderate Gas $0 Carbon (MG0) Avoided Cost scenario was used as the basis for determining the Solar-Weighted Avoided Energy Costs. Table 5 below depicts the average energy costs by month for the MG0 case for the year 2019.

For the first 1000MW tranche of distributed solar considered, the avoided costs used were the normal, budgeted avoided costs based on normal conditions with known and committed renewable resources. For subsequent tranches of distributed solar, new cases containing the combined impacts of the previously modeled tranches were created. These new cases served as the basis for the solar-weighted avoided energy cost calculations for these subsequent tranches.

**Table 5: Representation of MG0 Avoided Costs for 2019 ($/MWH)**

|  |
| --- |
| **REDACTED** |

The avoided energy costs were then applied to the distributed solar generation profile by hour for each year to calculate the expected avoided energy benefit. Table 6 shows the avoided energy costs for each solar generation tranche.

**Table 6: Avoided Energy Costs (M$)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Incremental PV (2015 M$) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Positive values represent benefits in the cost benefit determination.

The avoided energy cost for each solar tranche was then levelized on a 30-year basis using an **REDACTED** Weighted Average Cost of Capital (WACC) resulting in the solar-weighted avoided energy costs in Table 7 below.[[6]](#footnote-6)

**Table 7: Levelized Solar-Weighted Avoided Energy Costs ($/MWH)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Avoided Energy Costs | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Positive values represent benefits in the cost benefit determination.

**Deferred Generation Capacity Costs**

For purpose of this analysis and to establish a relative value of deferred generation capacity at various penetrations of distributed solar, it was assumed that no capacity value would be attributed until the first year of need for Georgia Power Company. For the first 1000MW tranche, this would be the year of need as identified in the official expansion plan (which includes all previously committed solar resources at the time the B2016 expansion plan was created). In this case, the first year of need in the B2016 expansion plan is 2024. For subsequent 1000MW tranches, the first year of need may or may not change, depending upon how the installation of the previous 1000MW tranches impacts capacity needs. This result was determined by the Strategist cases developed as a result of the Support Capacity calculations (discussed below).

The value of the deferred capacity was based upon the B2016 Retail Capacity Price forecast for Georgia Power Company as identified below in Table 8. Values are only shown beginning in the year of need.

**Table 8: B2016 Retail Capacity Price Forecast ($/kW-yr)**

|  |  |
| --- | --- |
| Year | Price Forecast |
| 2024 | **REDACTED** |
| 2025 | **REDACTED** |
| 2026 | **REDACTED** |
| 2027 | **REDACTED** |
| 2028 | **REDACTED** |
| 2029 | **REDACTED** |
| 2030 | **REDACTED** |
| 2031 | **REDACTED** |
| 2032 | **REDACTED** |
| 2033 | **REDACTED** |
| 2034 | **REDACTED** |
| 2035 | **REDACTED** |
| 2036 | **REDACTED** |
| 2037 | **REDACTED** |
| 2038 | **REDACTED** |
| 2039 | **REDACTED** |
| 2040 | **REDACTED** |
| 2041 | **REDACTED** |
| 2042 | **REDACTED** |
| Year | **Price Forecast** |
| 2043 | **REDACTED** |
| 2044 | **REDACTED** |
| 2045 | **REDACTED** |
| 2046 | **REDACTED** |
| 2047 | **REDACTED** |
| 2048 | **REDACTED** |

For the first 1000MW tranche, the capacity equivalent is determined based on the loss of load probability matrix for the existing system as modeled in the current budget. For the 1000MW tranche, the capacity equivalent was an ICE factor of 43%, declining with degradation to 37% by the end of the study. Ideally, the capacity equivalent for subsequent 1000MW tranches would be determined by recalculating the reliability impact of the next tranche assuming the previous tranche had been implemented. However, since this calculation could not be completed in the time frame associated with this study, an analysis was performed to determine how increasing levels of distributed solar penetration would impact the effective peak load. This impact of effective peak load was used as a proxy to determine the level of penetration at which distributed solar no longer has capacity worth.

Figure 2 below show a graphical representation of how various levels of distributed solar generation impact the effective load on a peak day in the year 2020. As the figure demonstrates, at distributed solar generation penetration levels of 7000MW and greater, there is a negligible impact on the peak load because the effective peak load has shifted to approximately 8PM, moving the effective peak into the evening (i.e., past sunset) hours. Although this graph shows a non-linear impact in declining capacity worth (i.e., the rate at which the capacity value falls is greater at lower levels of penetration), a conservative approach of assuming a linear decline in capacity worth was taken. The capacity worth for each of the eight solar tranches, therefore, was calculated as shown below in Table 9 following Figure 2. If the ICE factor calculation considered the forecast error and intra-hour volatility that the Support Capacity attempts to consider, the resulting ICE factor would be lower than the values shown in Table 9.

**Figure 3: Impacts of Distributed Solar on Effective Peak Load**

|  |
| --- |
| **REDACTED** |

Note: “Existing Renewables” reflects the impact of all renewable resources currently or committed to be installed on the Southern Company electric system by the year 2020.

**Table 9: Distributed Solar Generation First Year ICE Factor Assumptions**

|  |  |  |
| --- | --- | --- |
| Tranche | Decrease | ICE Factor |
| 1000 | 0% | 43.3% |
| 2000 | 17% | 36.1% |
| 3000 | 33% | 28.9% |
| 4000 | 50% | 21.7% |
| 5000 | 67% | 14.4% |
| 6000 | 83% | 7.2% |
| 7000 | 100% | 0% |
| 8000 | 100% | 0% |

As mentioned above, the first year in which the capacity benefit would apply would change with the subsequent 1000MW tranches based on the results of recalculating the expansion plan with the prior tranches included. In the base case, the year of need was 2024. For all eight 1000MW tranches, however, the year of need shifted to 2025.

The deferred generation capacity cost evaluation for each solar tranche was then calculated for each year for each tranche. Table 10 shows the results of this deferred capacity cost evaluation, which was then levelized on a 30-year basis using an **REDACTED** WACC resulting in the per-MWH deferred capacity costs in Table 11 below.

**Table 10: Deferred Generation Capacity Costs (M$)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Incremental PV (2015 M$) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Positive values represent benefits in the cost benefit determination.

**Table 11: Levelized Deferred Generation Capacity Costs ($/MWH)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Deferred Generation Capacity Costs | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Positive values represent benefits in the cost benefit determination.

**Deferred Transmission Investment**

As established in the Framework, the Deferred Transmission Investment represents the value of the transmission projects deferred as a result of additional distributed solar on the system. The deferred transmission investment was determined based on a previous study that was performed at the Southern Company electric system level and was calculated as follows. First, the long run (20 year) incremental cost of transmission expansion was identified. This cost included the various transmission projects that would be needed assuming 500MW of load growth per year[[7]](#footnote-7) starting in 2020 and continuing over a period of 20 years without installation of the distributed solar PV. The total transmission projects identified equated to a total long run incremental cost of transmission of **REDACTED** [[8]](#footnote-8) in 2015$.

Using these projects as a baseline, 1000MW solar tranches at the system level were evaluated to determine which transmission projects could be deferred (and for how many years) as a result of adding the distributed solar. The amount of distributed solar that was assumed to be available and offsetting load at the peak (i.e., coincident with the transmission peak load) was **REDACTED** [[9]](#footnote-9) of the installed amount (i.e., 534MW for each 1000MW tranche). The deferral cost (i.e., the Economic Carrying Cost or ECC) of these projects then served as the basis for determining the avoided transmission cost associated with each solar tranche. Table 12 below shows a summary of the calculated avoided transmission cost for each solar tranche using this methodology.

**Table 12: 20-Year Deferred Transmission Investment Cost (M$)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Cumulative PV (2020 M$) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Incremental PV (2020 M$) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Positive values represent benefits in the cost benefit determination.

Because the deferred transmission analysis was performed on a 20-year basis and the remainder of the solar cost benefit analysis was performed on a levelized 30-year basis, the transmission deferred cost values were converted to a 30-year basis for consistency. This conversion was accomplished by converting the results of the 20-year analysis into an ECC. The ECC values were then escalated at an inflation rate of 2.0% for 30 years and its 30-year equivalent NPV was calculated and also converted from 2020$ to 2015$. The results of this conversion are shown below in Table 13.

**Table 13: 30-Year Equivalent Deferred Transmission Investment Cost**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Incremental PV (2015 M$) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Positive values represent benefits in the cost benefit determination.

Finally, these values were levelized consistent with the other cost-benefit components. Table 14 below shows these results.[[10]](#footnote-10)

**Table 14: Levelized Deferred Transmission Investment Costs ($/MWH)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Deferred Transmission Costs | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Positive values represent benefits in the cost benefit determination.

**Reduced Distribution Losses**

As established in the Framework, a system-weighted distribution loss profile was applied to the eight-1000MW solar tranche profiles and then evaluated against avoided energy costs to determine their distribution loss impact.[[11]](#footnote-11) Because system avoided costs only include losses down to the transmission substation level, the loss factors for the distributed losses were calculated based on losses from the transmission substation level down to the distribution feeder level. Although an 8760-hour loss factor profile was used, the average avoided distribution loss impact associated with the distributed solar across the year was **REDACTED** of the distributed solar profile. This 8760 hourly loss factor was applied to the 8760 distributed solar generation profile in each year to calculate an 8760 loss profile for each year. This loss profile, like the distributed solar generation profile, was then multiplied in each hour by the avoided energy cost to get the avoided distribution losses cost. Table 15 below shows the levelized avoided distribution losses cost values that resulted from this calculation.

**Table 15: Levelized Reduced Distribution Losses ($/MWH)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Reduced Distribution Loss | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Positive values represent benefits in the cost benefit determination.

**Distribution Operations Costs**

Georgia Power Company has not yet developed a methodology to calculate the expected distribution operating costs associated with significant penetrations of distributed solar. Therefore, this section is included as a placeholder for future updates to this analysis.

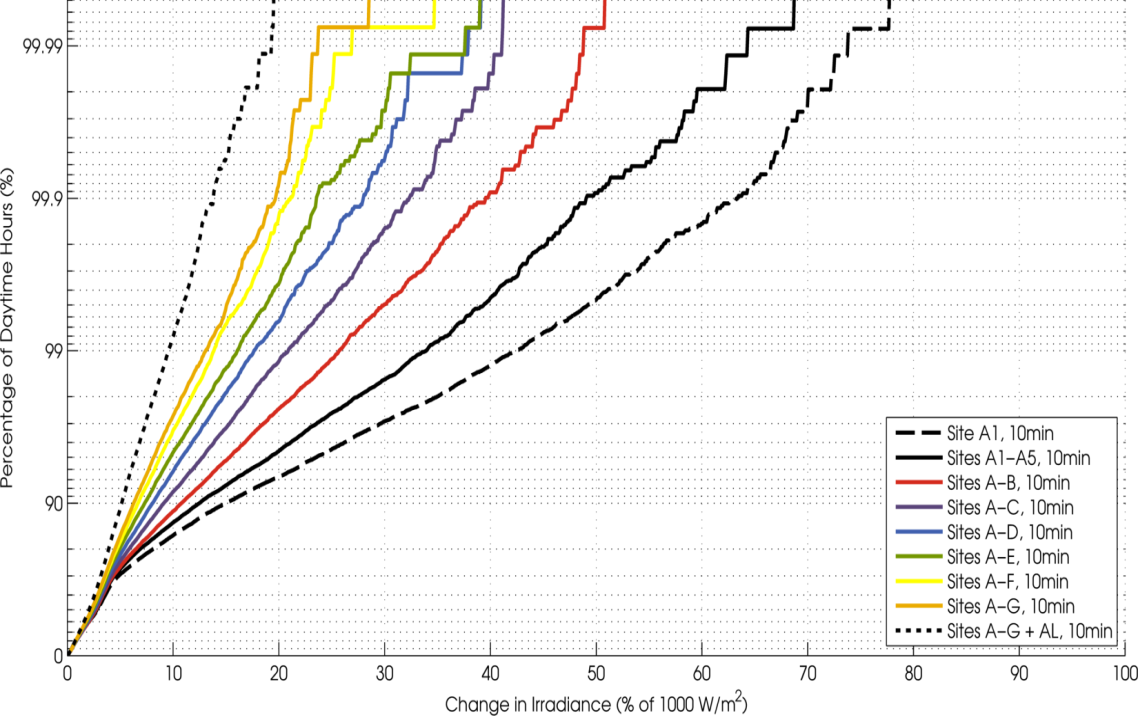
**Ancillary Services – Reactive Supply and Voltage Control**

Georgia Power Company has not yet developed a methodology to calculate the expected reactive supply and voltage control costs associated with significant penetrations of distributed solar. Therefore, this section is included as a placeholder for future updates to this analysis.

**Ancillary Services – Regulation**

The incremental Regulating Reserve requirement associated with the distributed solar was determined using 10-minute solar output data from the EPRI research project titled *Distributed PV Monitoring and Feeder Analysis 2010-2014* (EPRI Study). This study evaluated the solar production of a wide distribution of pole-mounted solar panels spread across the states of Georgia and Alabama. A series of geographically diverse sets of output data (ranging from a single site to an aggregate of all the sites studied) were analyzed to determine their 10-minute ramp volatility. The results are shown in Figure 4 below.

**Figure 4: Ramp rate cumulative frequency, 10-minute intervals, and various DPV aggregations.**



From this figure, it can be seen that the 10-minute ramp varies widely from a single installation to a highly geographically diverse set of installations. Because NERC BAL-001 Reliability Standard requires Balancing Authorities to establish Regulating Reserve requirements that are sufficient such that Area Control Error crosses the zero point in at least 90 percent of the 10-minute periods in each month, the 95th percentile of the 10-minute ramp volatility was chosen to establish the impact that distributed solar generation has on Regulating Reserve requirements.[[12]](#footnote-12) At the 95th percentile, the 10-minute ramp volatility ranges from approximately 25% for a single facility to below 10% for an aggregation of widely dispersed facilities. For this analysis, which is evaluating the costs and benefits of a highly diverse penetration of distributed solar, it was determined that the appropriate 10-minute ramp curve to use from the EPRI Study was the one labeled “Sites A-G + AL, 10min,” which represents the most geographically diverse aggregation of the research data. The 95th percentile of the 10-minute ramp for this curve is roughly 5%. In other words, for each 100MW of solar added to the system, there is a need for an additional 5MW of regulation and, as a result, a 5 MW increase in capacity requirements because that capacity is no longer available to serve peak load. Thus, for purposes of this study, the additional Regulating Reserves required as a result of the addition of distributed solar – and the amount of additional capacity needed on the system as a result of this increased requirement – was assumed to be 5% of the installed amount or 50MW for each 1000MW distributed solar tranche. The cost impact associated with these additional reserves is reported in the Support Capacity results below.

**Generation Remix Costs**

Generation Remix costs include a capital component and a production component. In accord with the Framework, the Generation Remix Capital costs were determined by performing Strategist runs for each incremental tranche with the solar tranche added and comparing the resulting expansion plan to the expansion plan without the solar tranche. The differences in the expansion plan were valued at the ECC of the specific generation technology selected in the Strategist runs. Using these costs, the Generation Remix capital component costs/(savings) were calculated for each tranche. However, as indicated in the Framework, because these costs also include the Deferred Capacity benefits, those benefits were subtracted from this calculation to eliminate double counting those benefits. Table 16 shows the NPV of these Generation Remix capital costs in 2015$.

**Table 16: Generation Remix Capital Costs (Millions of Dollars)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Incremental PV (2015) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Positive values in this table represent benefits.

Pursuant to the Framework, the Generation Remix Production costs were determined by performing PROSYM runs for each incremental tranche using the incremental solar profiles and expansion plans determined during the capital cost evaluation and then comparing the resulting production cost to the production cost of the prior case. As indicated in the Framework, the avoided energy cost for the tranche was subtracted from this calculation to avoid double counting those benefits. Table 17 shows the NPV of the Generation Remix production costs in 2015$.

**Table 17: Generation Remix Production Costs (Millions of Dollars)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Incremental PV (2015) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Negative values in this table represent costs.

The total Generation Remix costs, therefore, equals the sum of the Generation Remix Capital costs and the Generation Remix Production costs. Table 18 shows the total Generation Remix Costs.

**Table 18: Total Generation Remix Costs (Millions of Dollars)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Incremental PV (2015) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Negative values in this table represent costs.

These values were then converted into 30-year levelized values as shown in Table 19.

**Table 19: 30-Year Levelized Generation Remix Production Costs ($/MWH)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Generation Remix Costs | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Negative values represent costs in the cost-benefit determination.

**Support Capacity**

In accord with the Framework, the total amount of Support Capacity needed for each of the distributed solar tranches was determined by calculating the sum of:

1. The incremental Regulating Reserve requirement;
2. The impact of the forecast error associated with the incremental distributed solar on expected unserved energy; and
3. Any additional generation ramp requirements in excess of the forecast error amount.

For each of the three factors identified above, the impact was determined according to the procedure and methodology set forth in the Framework.

As identified in the Ancillary Services-Regulation section above, the Regulating Reserve portion of Support Capacity was determined to be 50MW per 1000MW solar tranche as shown in Table 21 below in the row labeled “Regulation Impact.” Strategist does not specifically model Regulation. Therefore, the capacity costs associated with this 50MW Regulation requirement was valued at the ECC of a CT beginning in the year of need.

Per the Framework, the Solar Forecast Error portion of the Support Capacity was determined by developing an 8760 solar forecast error table from the solar data in the EPRI Study. A “persistent forecast” assumption[[13]](#footnote-13) was made from the data and a resulting assumed forecast error for each hour was determined. Although an 8760 forecast error profile was developed and used, Table 20 shows the average hourly solar forecast error by month that was assumed for the analysis.

**Table 20: Hourly Solar Forecast Error**

|  |
| --- |
| **REDACTED** |

This forecast error matrix was then applied to the latest Loss of Load Probability table [[14]](#footnote-14) to determine the expected impact that the assumed solar forecast error would have on expected unserved energy. That calculation indicated that solar forecast error resulted in an impact to the solar capacity value of **REDACTED** of the installed solar capacity. In other words, for each 100MW of solar installed on the system, there is a need for **REDACTED** of “backup capacity” (in addition to the additional capacity needed for regulation) to restore the system to its previous level of assumed reliability. This **REDACTED** was applied to each 1000MW solar tranche to determine the amount of Support Capacity needed as a result of solar forecast error and is shown in Table 21 below in the row labeled “Forecast Error Impact.”

The incremental generation ramp portion of the Support Capacity was determined by comparing the maximum 3-hour generation ramp of the load forecast starting in 2020 with the maximum 3-hour generation ramp net of each of the solar tranches. Any increase in ramp over the base case reflected an assumed need for incremental ramping generation, shown in Table 21 below as “Total Ramp Impact.” The ramping portion of the Support Capacity was assumed to be able to perform “double duty” with the solar forecast error portion of Support Capacity to the extent that incremental ramping capacity was only added when the identified need exceeded the identified capacity associated with solar forecast error. This is shown in Table 21 below in as “Generation Ramp Need.” Therefore, “Total Ramp Impact” shows the total incremental generation ramping impact but only that amount shown as “Generation Ramp Need” actually impacted the Support Capacity calculation.

Table 21 below shows the results of the determination of the incremental Regulating Reserve requirement, Solar Forecast Error impact, and incremental Generating Ramp requirement for each of the 1000MW solar tranches. Together, these represent the Support Capacity requirements for each solar tranche.

**Table 21: Incremental Support Capacity Requirements by Solar Tranche (MW)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Solar Tranche | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Regulation Impact | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Forecast Error Impact | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Total Ramp Impact | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Generation Ramp Need | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

These Support Capacity requirements were added to Strategist to determine – relative to the Strategist case with the distributed solar tranche added – any advancement costs (or deferral benefits) associated with the addition of these requirements. The difference in resulting capital costs between each solar tranche case and their respective base cases represents the capital cost associated with Support Capacity. Table 22 below shows the NPV differences in capital costs for each solar tranche.

**Table 22: Support Capacity Capital Costs (Millions of Dollars)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Solar Tranche | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Incremental PV (2015 M$) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Negative values in this table represent costs

As specified in the Framework, the Support Capacity production costs were calculated by modeling the expansion plan results from the Strategist cases in PROSYM and calculating the differences in production costs. In addition to modeling the expansion plan changes, the additional regulating reserves were modeled in PROSYM as an increase in spinning reserve requirement. Table 23 shows the results of the Support Capacity production cost calculations.

**Table 23: Support Capacity Production Costs (Millions of Dollars)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Solar Tranche | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Incremental PV (2015 M$) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Negative values in this table represent costs.

The sum of the Support Capacity Capital costs and the Support Capacity Production costs represents the total Support Capacity Costs, shown below in Table 24.

**Table 24: Total Support Capacity Costs (Millions of Dollars)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Solar Tranche | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Incremental PV (2015 M$) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Negative values in this table represent costs.

These values were then converted into 30-year levelized values in $/MWH as shown in Table 25.

**Table 25: Levelized Support Capacity Capital Costs ($/MWH)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Solar Tranche | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Support Capacity Capital Costs | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Negative values represent costs in the cost benefit determination.

**Bottom Out Costs**

Per the Framework, the methodology for determining Bottom Out costs was based upon the Strategist and PROSYM cases from the Support Capacity calculation.

For this particular analysis, however, due to the recommitment algorithm in PROSYM, there was no need to manually decommit any resources.[[15]](#footnote-15) As such, there were no intermediate cases from which DUMP ENERGY costs could be derived. Therefore, the Bottom Out costs were merely the increase in DUMP energy in the PROSYM cases (from the base case to the tranche change case) valued at the avoided energy cost from the PROSYM cases. Table 26 below shows the amount of aggregate DUMP energy in excess of the base case that resulted from each solar tranche.

**Table 26: Incremental Dump Energy relative to Base Case (GWh)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| 2019 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2020 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2021 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2022 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2023 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2024 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2025 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2026 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2027 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2028 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2029 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2030 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2031 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2032 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| 2033 |  |  |  |  | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

From this table, it is evident that there was no incremental DUMP energy prior to the 5000MW distributed solar tranche. This indicates that the system should be able to recommit around known and reliable solar energy profiles up to the point of having around 5000MW of solar. This is not to say there would not be bottom out conditions attributable to solar prior to 5000MW of penetration, but rather such conditions could be more readily expected at penetration levels of 5000MW and above. It should be noted that Utility Scale solar implementations that have significantly higher capacity factors are likely to result in greater amounts of DUMP energy at lower levels of penetration.

The hourly incremental DUMP energy represented by the aggregate annual DUMP energy was valued at the hourly-avoided energy costs to determine the cost of Bottom Out conditions associated with distributed solar. The result of this evaluation is shown in Table 27 below.

**Table 27: Bottom Out Costs (Millions of Dollars)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Solar Tranche | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Incremental PV (2015 M$) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Negative values in this table represent costs.

These Bottom Out costs for each solar tranche were then levelized on a 30-year basis using an **REDACTED** WACC resulting in the avoided bottom out costs in Table 28 below.

**Table 28: Levelized Bottom Out Costs ($/MWH)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Solar Tranche | 1000 | 2000 | 3000 | 4000 | 5000 | 6000 | 7000 | 8000 |
| Bottom Out Costs | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Negative values represent costs in the cost benefit determination.

**Long Term Service Agreement (LTSA) Maintenance Costs**

Georgia Power Company has not yet developed a methodology to calculate the expected starts based maintenance costs associated with significant penetrations of distributed solar. Therefore, this section is included as a placeholder for future updates to this analysis.

**Target Reserve Margin Costs**

Georgia Power Company has not yet completed studies to calculate the expected planning reserve margin costs associated with significant penetrations of distributed solar. The planning reserve margin studies are expected to be completed in 2015 as part of the 2016 IRP process. The results of the planning reserve margin study were not available in time for inclusion in this analysis. Therefore, this section is included as a placeholder for future updates to this analysis.

**Program and Administration Costs**

Georgia Power Company has not yet developed a methodology to calculate the expected administrative costs associated with significant penetrations of distributed solar. Therefore, this section is included as a placeholder for future updates to this analysis.

**Conclusions**

As stated in the Executive Summary, the following conclusions can be drawn from these results:

1. The total benefit provided by solar generation exceeds the total cost caused by solar generation; however, with increasing penetration levels the overall benefit to the system declines.
2. On average (after the 2000MW tranche and excluding the 8000MW tranche which represents a substantial cost breakpoint), the decline in the total avoided cost of solar amounts to roughly **REDACTED** for each 1000 MW of solar installed on the system (i.e., each 1000 MW of distributed solar installed – up to 7000MW - is worth about **REDACTED** less than the previous 1000 MW installed).
3. Total avoided costs remain fairly stable up through 2000MW of distributed solar, after which the costs tend to decline steadily until the next big cost breakpoint at 7000MW of distributed solar – the point at which there is no longer a deferred generation capacity and deferred transmission investment benefit from distributed solar due to the time shift of the peak to dusk.
4. Compared to the avoided energy benefits provided by distributed solar, the deferred transmission investment benefits are extremely small on a relative basis.
5. Costs associated with Support Capacity and Generation Remix are immediately incurred with low penetrations of solar.
6. Even with perfect knowledge and perfect confidence in the expected solar profile, the system reaches a point between 4000 and 5000 MW of distributed solar in which it can no longer recommit to avoid bottom out conditions; although the costs are estimated to be relatively low (as calculated here using avoided energy cost as a proxy for over generation costs), it can be assumed that this increase in bottom out conditions represents a significant increase in the operational challenges associated with solar generation.

Based on these conclusions, all new proposed solar resources should be evaluated in light of all previously committed solar projects so that the declining value of solar generation can be appropriately measured. Based on today’s view of the future, it can also be concluded that due to the significant breakpoints in operational costs associated with solar and the potential for significant increases in operational problems at these levels, consideration of solar penetrations in the 4000-5000 MW range could create the need for mitigation measures. Although this study was performed for distributed solar generation, the general conclusions are applicable to all solar generation added to the system, including utility scale solar generation.

1. In this case, the existing planning case is the latest base case including all existing solar and wind commitments but not including those solar resources recommended as part of the 2016 Integrated Resource Plan. [↑](#footnote-ref-1)
2. As defined in the Framework document. [↑](#footnote-ref-2)
3. All values are in $/MWH of solar generation. Positive values represent benefits. Negative (red) values represent costs. Areas that are shaded are components that, while appropriately factored into an assessment of the costs and benefits of solar, were not calculated in this iteration of the cost-benefit analysis because the methodology is still under development. These results show relative impacts of various levels of sustained distributed solar generation and are for comparison purposes only. They are not indicative of any specific value of distributed solar generation in any particular year, and should not be used to price any particular distributed solar program. Should there be a need to develop such pricing mechanisms, an analysis should be performed using consistent Framework methodologies and project-specific details and assumptions. [↑](#footnote-ref-3)
4. A levelized value is a single value that can be applied annually much like an annuity or mortgage payment. These levelized values were calculated by determining the annual annuity value that produces the same Net Present Value as the nominal stream of costs and benefits considered in the analysis. [↑](#footnote-ref-4)
5. http://maps.nrel.gov/prospector [↑](#footnote-ref-5)
6. The energy component of deferred transmission losses is included as part of these avoided energy costs. [↑](#footnote-ref-6)
7. Across the entire Southern Company electric system. [↑](#footnote-ref-7)
8. Determined as the sum of the capital costs of all the projects identified in the study (in 2015$) divided by the assumed long-term load growth of 10,000MW. [↑](#footnote-ref-8)
9. Determined as the average expected output of the distributed solar during hours 15 and 16 (3-4PM) in the months of June-August. [↑](#footnote-ref-9)
10. The demand component of deferred transmission losses is included as part of this deferred transmission cost. [↑](#footnote-ref-10)
11. This distribution loss profile included impacts of transmission substation losses, subtransmission substation and line losses, distribution substation losses, and distribution line losses. [↑](#footnote-ref-11)
12. Choosing the 90th percentile would create risk that the Balancing Authority could not meet the requirements in the standard and choosing the 100th percentile would have been overly conservative, resulting in greater than necessary cost impacts. [↑](#footnote-ref-12)
13. A “persistent forecast” is one in which the current hour’s actual output is used as a basis for determining the forecast for the next hour. Since solar forecast data was not available, a “persistent forecast” was developed from the historical output. This manufactured forecast served as the basis for determining the forecast error. [↑](#footnote-ref-13)
14. The latest version of the Loss of Load Probability table is from the B2012 Reserve Margin Study that was performed in support of the 2013 IRP. The reserve margin study is being updated in 2015 for the 2016 IRP but was unavailable at the time this study was performed. [↑](#footnote-ref-14)
15. Section 4 of the Framework document describes the methodology for calculating the various components. For the Bottom Out component, the methodology requires a comparison of DUMP ENERGY from the Base Case to the renewable case. However, if the DUMP ENERGY of the renewable case is too large, PROSYM modelers may be required to perform a partial manual re-commitment of the system before finalizing the renewable case. The cost associated with the intermediate step must be determined to fully capture the Bottom Out costs. This intermediate step was not deemed necessary for this analysis. [↑](#footnote-ref-15)