**STATE OF GEORGIA**

**BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION**

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| **In Re:** **2019 Integrated Resource Plan and Application for Certification of Capacity from Plant Scherer Unit 3 and Plant Goat Rock Units 9-12 and Application for Decertification of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2** | **)**  **)**  **)**  **)**  **)**  **)** | **DOCKET NO. 42310** |

DIRECT TESTIMONY OF MICHAEL S. GOGGIN

ON BEHALF OF

SOUTHERN RENEWABLE ENERGY ASSOCIATION

April 25, 2019

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**Introduction**

**Q: Please state your name and job title.**

**A:** Michael Goggin, and I am Vice President at Grid Strategies LLC, a consulting firm based in the Washington, D.C., area.

**Q: For whom are you testifying?**

**A:** I am testifying on behalf of the Southern Renewable Energy Association.

**Q: Have you previously testified before the Georgia Public Service Commission (“PSC”) or other state Commissions?**

**A:** Yes, in the 2016 Georgia Power Integrated Resource Plan (IRP) case (Docket No. 40161) in 2016. I have also testified before state utility commissions in Illinois, Indiana, Minnesota, Missouri, Ohio, Oklahoma, Virginia, and Wisconsin.

**Q: What is your background and educational experience?**

**A:** I have worked on renewable energy, transmission, and electricity market issues for nearly 15 years. At Grid Strategies I serve as an expert on those topics for a range of clean energy industry and environmental advocate clients. For the preceding ten years I worked at the American Wind Energy Association, where I provided technical analysis and advocacy regarding renewable energy, transmission, and renewable integration into electricity markets, including directing the organization’s research and analysis team from 2014-2018. Prior to the American Wind Energy Association, I worked at a firm serving as a consultant to the U.S. Department of Energy.

In the course of that work, I have co-authored nearly one hundred filings with the Federal Energy Regulatory Commission; served as a technical reviewer for over a dozen national laboratory reports, academic articles, and renewable integration studies; and published academic articles and conference presentations on renewable integration, transmission, and policy. I graduated with honors from Harvard University.

**Q: What is the conclusion of your testimony?**

**A:** By not allowing renewable resources to compete in its economic evaluation, Georgia Power’s IRP deprives Georgia Power customers of significant net benefits they could receive from renewable capacity additions greater than the 1,000 MW proposed in the IRP. To remedy that, Georgia Power should conduct an all-source evaluation, incorporating market-based offers gathered through a Request For Proposals, and then procure the quantity of renewable generation that will optimize net benefits for Georgia Power customers. In that all-source evaluation and procurement, Georgia Power should correct a number of economic and reliability assumptions in the IRP that overstate the costs and understate the benefits of renewable energy.

**Q:** **Please summarize your testimony.**

**A:** First, I note that Georgia Power’s IRP did not allow renewable resources to compete in its economic evaluation, despite significant cost-effective supply of and demand for renewable resources. Second, I explain how economic assumptions in documents that accompany the IRP overstate the costs and understate the benefits of renewable energy, and note the urgency of procuring renewable resources to take advantage of federal tax credits before they phase down. Third, I explain how renewable resources contribute to electric reliability, and how the assumptions in Georgia Power’s IRP understate those contributions. Fourth, I explain how Georgia Power’s proposed Winter Reserve Margin can be replaced by method that will more consistently and comprehensively evaluate the capacity value contributions of all resources across all seasons. Fifth, I explain how capacity-driven planning processes ignore opportunities to replace existing generation with more cost-effective alternatives. Finally, I offer a framework by which Georgia Power can conduct an all-source resource evaluation and procurement that corrects for the flaws identified above.

**I. Georgia Power did not allow renewable resources to compete in its IRP**

**Q: Did Georgia Power’s IRP evaluate the economically optimal level of renewable energy deployment?**

**A:** No, there was no evaluation of the competitiveness of renewable generation versus Georgia Power’s existing fleet or proposed generating capacity additions. Georgia Power’s IRP explains that “Intermittent resources, such as solar and wind, were not included as selectable technologies for the expansion planning model but instead were reflected in the model as planned and committed resources. Such planned resources include the Company’s recommended addition of 1,000 MW of renewable resources.”[[1]](#footnote-1) Had Georgia Power’s IRP economically evaluated renewable energy, it almost certainly would have found an optimal deployment larger than 1,000 MW.

**Q: Did Georgia Power evaluate additions of renewable energy greater than that amount?**

**A:** In the Renewable Cost Benefit (RCP) Framework that was filed to accompany the IRP, Georgia Power evaluated the economic value of incremental additions of [REDACTED]. In each case, the value of [REDACTED] was significantly higher than the current cost at which those resources are available in the market. No justification was provided for the IRP only recommending the addition of 1,000 MW of renewable generation [REDACTED] was available at a net benefit. Georgia Power also offered no justification for not evaluating wind or solar additions greater than [REDACTED]. Notably, Georgia Power evaluated significantly higher wind and solar capacity levels in its 2016 IRP, and found high value for those additions.

**Q: How do the value calculations for wind and solar compare to current costs for those resources?**

**A:** In the IRP, Georgia Power notes that it is paying an average of $36/MWh for solar generation purchased following a 2017 RFP for REDI Utility-Scale Procurement: “The first RFP required projects to achieve commercial operation in 2018 or 2019. From this solicitation, Georgia Power entered into 30-year PPAs with three suppliers for a total of 510 MW of in-state solar capacity, with an average price of 3.6¢/kWh.”[[2]](#footnote-2) For comparison, the RCB analysis found the value of an additional [REDACTED].

Wind energy also offers low costs and large net benefits. Wind Power Purchase Agreements (PPAs) signed in 2017 averaged $18.91/MWh in the interior region of the country.[[3]](#footnote-3) The interior region includes the Southwest Power Pool states from which Georgia Power and other Southern Company operating companies have previously purchased wind generation, and the RCB benefit analysis was based on Oklahoma wind. Georgia Power’s analysis of wind benefits conservatively assumed 10% transmission losses between Oklahoma and the Southern Company system so that cost is already accounted for, though the cost of transmission service would have to be accounted for in addition to the PPA price. However, as long as the cost of transmission service is under [REDACTED], procuring additional wind generation should provide significant net benefits to Georgia Power.

It should also be noted that Georgia Power’s RCB analysis did not evaluate the value of utility solar with single-axis or even dual-axis tracking, even though projects with trackers accounted for 79% of solar capacity installed nationwide in 2016 and 2017, a share that has increased from 50% in 2011 and continues to grow.[[4]](#footnote-4) As discussed in more detail later in my testimony, solar projects with trackers offer significantly higher energy and capacity value, and reduced output variability and uncertainty, relative to fixed solar installations. These benefits more than outweigh the modestly higher cost of trackers, as evidenced by the growing market share of tracking solar relative to fixed tilt solar.

**Q: Are larger quantities of renewable energy available to Georgia Power?**

**A:** Yes. Wind energy supply is not a limitation, as the Southwest Power Pool interconnection queue currently has over 60,000 MW of proposed wind projects with active interconnection applications.[[5]](#footnote-5) Similarly, the American Wind Energy Association reports that as of the end of 2018, at least 3,481 MW of wind projects are under construction or in advanced development in Kansas and Oklahoma alone.[[6]](#footnote-6)

The Southeast has abundant supply of, and demand for, renewable energy. The Southern Company and Georgia Power interconnection queues contain large quantities of proposed solar projects, further demonstrating that renewable resources are economically viable and available for procurement. Specifically, there are 13,225 MW of solar PV generating capacity in the Southern Company interconnection queue, of which 8,375 MW, or 63%, are located in Georgia.

Demand for renewable energy among Georgia Power customers also greatly exceeds the quantity Georgia Power has procured to date. As noted in the IRP’s discussion of the prior round of the C&I REDI Program, “As a result of the NOI process, four customers expressed interest for more than 400 MW of capacity, which exceeded the program supply target amount of up to 200 MW.”[[7]](#footnote-7) If Georgia Power’s planning and procurement continues to fall short of customer demand for renewable energy, large customers should be allowed to directly procure renewable energy resources, as they are in most other states.

**II. Flaws in Georgia Power’s economic assumptions about renewable energy**

**Q: How do the solar cost assumptions in Georgia Power’s 2019 Generation Technology Data Book (GTDB) compare to cost data from other sources?**

**A:** Georgia Power’s GTDB overestimates solar costs relative to other data sources, as shown below. While the economic analysis in Georgia Power’s IRP did not allow renewable energy to compete against conventional generation, Georgia Power did include renewable cost assumptions in the GTDB that was filed with the IRP. As a result, these assumptions should be revised if Georgia Power proceeds with the all-source economic analysis recommended in my testimony.

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| --- | --- | --- | --- |
|  | Georgia Power GTDB | Lazard[[8]](#footnote-8) | NREL[[9]](#footnote-9) |
| Capital cost ($/kW) | [REDACTED] | $950-1250 | $941-1111 |

A possible explanation for the difference is that Georgia Power’s cost estimates have not kept pace with recent declines in the cost of renewable energy. The GTDB indicates that solar plant costs are overnight costs as of [REDACTED] while the wind “Cost information is based on a sample of data received as part of an engineering study performed by SCS E&CS in early 2017.”

**Q: What is the expected future trend of renewable energy costs?**

**A:** The widely-held expectation is that cost reductions will continue, bringing solar and wind well below the cost of other generation options. These expected declines should be factored into Georgia Power’s economic analysis, as most of Georgia Power’s proposed procurements are scheduled for later in the next decade.

A recent Bloomberg report found that the cost of new wind and solar power facilities in the Midwest fell by 16 percent and 23 percent respectively from 2017 to 2018.[[10]](#footnote-10) NREL’s conservative cost projections call for continued cost declines of 18% for wind and 27% for solar through the year 2030.[[11]](#footnote-11) Industry sources are even more optimistic, expecting unsubsidized wind costs to reach $20-30/MWh and solar costs to reach $30-40/MWh in the early 2020s.[[12]](#footnote-12) Part of the reason is that after the federal tax credits expire, wind developers and potentially solar developers will no longer need to use tax equity financing to monetize the tax credits, which they can replace with debt financing at a significantly lower cost.[[13]](#footnote-13) As a result, renewable developers are announcing large deployment plans following the expiration of the tax credits, particularly in the Midwest.[[14]](#footnote-14)

**Q: What are Georgia Power’s cost assumptions for battery storage?**

**A:** Documents submitted with the IRP show that Georgia Power anticipates a cost of [REDACTED]. In contrast, Lazard’s analysis shows current capital costs for a 100 MW 4-hour duration lithium ion battery at $1,140-1,814/kW, with a further 28% reduction in costs expected by 2022.[[15]](#footnote-15) More generally, Georgia Power should include energy storage, renewable energy, and hybrid projects using both renewable energy and battery storage in its competitive analysis of the cost and benefits of different resource options, accounting for the full stack of value streams storage resources can provide.

**Q: Should other economic assumptions be revised for that competitive analysis?**

**A:** Yes. Georgia Power’s assumed capital costs for both combined cycle and simple cycle gas generation are very low compared to data from the Department of Energy’s Energy Information Administration (EIA), Lazard, and other sources. EIA shows the overnight capital costs for advanced combined cycle at $794/kW, and conventional combined cycle at $999/kW,[[16]](#footnote-16) while Lazard shows a range of $700-$1,300/kW.[[17]](#footnote-17) In contrast, Georgia Power’s estimate for combined cycle capital cost is significantly lower at [REDACTED], depending on the plant configuration. Similarly, Georgia Power estimates combustion turbine capital costs at [REDACTED] depending on the size and whether the plant has dual-fuel capability. In contrast, EIA shows $658/kW for advanced combustion turbines and $1072/kW for conventional combustion turbines, while Lazard shows a range of $700-$900/kW. EIA’s data show that regional cost variations only result in the levelized cost of those resources coming in at maximum 10% below the national average,[[18]](#footnote-18) so regional cost variations alone do not explain the low estimates in Georgia Power’s GTDB. This error biases Georgia Power’s economic analysis towards adding gas generation resources.

Q**: Should Georgia Power expedite wind and solar procurement to take advantage of the availability of federal tax credits?**

**A:** Yes. The federal wind Production Tax Credit (PTC) began to phase down in 2017. If it moves quickly, Georgia Power could likely contract with wind projects that qualified for the full tax credit in 2016 and are now under development and seeking buyers for their power.

To qualify for the full federal wind production tax credit of $24/MWh, by the end of 2016 wind projects had to either begin physical construction or achieve “safe harbor” status by incurring a significant share of total project costs and taking delivery of that equipment shortly thereafter.[[19]](#footnote-19) Wind projects that took those steps by the end of 2017 qualified for 80% of the full value PTC, those that did so by the end of 2018 qualify for 60% of the full value PTC, and projects doing so in 2019 will only receive 40% of the full value PTC.

Most wind projects use the safe harbor approach, which also requires them to reach commercial operations within four years of the year in which they qualified for the PTC. As a result, many projects that qualified in 2016 are likely looking to find buyers and begin physical construction as soon as possible in order to achieve commercial operations by the end of 2020.

Similarly, the 30% solar investment tax credit begins to phase down at the end of 2019, dropping to 26% in 2020, 22% in 2021, and 10% in 2022 for utility and commercial-scale solar (while residential drops to 0% in 2022). Solar projects must be placed in service by the end of 2023.[[20]](#footnote-20) Solar developers are making decisions this year about how much solar capacity to qualify for the full value tax credit. If Georgia Power indicates solar procurement plans by the end of the year, it can reduce developers’ business uncertainty costs and therefore likely procure solar resources at a lower cost. Many of the renewable procurement plans identified in the Georgia Power IRP occur too late in the 2020s to take advantage of the tax credits, increasing costs for Georgia ratepayers by up to 20% for utility-scale solar and even more than that for wind. In conducting its all-source solicitation procurement, Georgia Power should allow developers to submit differently priced offers based on the timing of their proposed deployment, as this will allow Georgia Power to time renewable additions to maximize ratepayer savings.

**Q: How do renewable resources affect the risk fuel price and environmental policy uncertainty in Georgia Power’s analysis?**

**A:** Georgia Power’s analysis includes a range of scenarios to illustrate the impact of fuel price risk and carbon price risk on various generation portfolios. Renewable resources are immune to both of these risk factors, so had Georgia Power included renewable resources as a selectable resource in its economic analysis, it would have shown that renewable resources increase the resilience of the generating portfolio to these risks. This would result in reduced costs for Georgia ratepayers in cases with high gas prices or high carbon costs, in addition to the hedging value of reducing electricity price risk for these consumers. Much like the risk reduction value of an insurance policy, a hedged portfolio of investments, or a fixed-rate mortgage, renewables provide significant value to consumers by reducing fuel price and carbon price risk.

**Q: Do Georgia Power’s modeling results show the value of reducing fuel price risk and carbon price risk?**

**A:** Yes. The high gas price scenario results in consumer costs that are [REDACTED] higher than the base case, and [REDACTED].

**Q: How would the optimal portfolio likely have shifted if renewable resources were allowed to economically compete with conventional generators in the IRP Mix Study?**

**A:** [REDACTED].[[21]](#footnote-21) Had renewable resources been a selectable option in the analysis, the modeling likely would have shown a shift to renewable resources in the high gas price and carbon price cases as a way to reduce fuel consumption and associated emissions.

**Q: Is Georgia Power’s treatment of carbon prices realistic?**

**A:** [REDACTED],[[22]](#footnote-22) but the expected value for a carbon price over the multi-decadal life of generation assets being planned in this IRP is certainly greater than that. In addition, the IRP only evaluating carbon price scenarios up to [REDACTED] understates the potential for significantly higher carbon prices over the lifetime of new generation resources. The last Administration’s estimate for the social cost of carbon,[[23]](#footnote-23) and the carbon price that has been proposed in New York,[[24]](#footnote-24) is roughly [REDACTED] and increasing to [REDACTED] over the next decade.

**Q: Have other studies evaluated the value of non-fossil resources for hedging fuel price risk?**

**A:** Yes. The fuel price hedging value of solar generation was calculated to be $6.60/MWh in Colorado, which is significant as Colorado’s energy mix is less reliant on gas generation than Georgia Power’s.[[25]](#footnote-25)

In Virginia, Dominion’s IRP included analysis of the gas price hedging value of adding a third unit at the North Anna nuclear plant. This result applies at least equally well to additions of renewable energy, as wind and solar have no fuel price or fuel price risk. As I explained in testimony before the Virginia Corporation Commission,

*VEPCO’s North Anna 3 analysis shows this benefit to be significant, equivalent to the risk reduction of fully hedging around 16% of VEPCO’s gas consumption needs. This was found to provide a 12% reduction in the standard deviation of electricity prices (as a share of the standard deviation), reducing the standard deviation by around $1.10/MWh.[[26]](#footnote-26) Substituting that amount of a fixed-price resource, whether wind or nuclear, for gas generation would therefore result in savings of around $175 million annually in the credible scenario in which fuel prices are two standard deviations higher than expected.*

**III. Georgia Power’s analysis understates the reliability value of renewable resources**

**Q: What capacity value did Georgia Power calculate for solar?**

**A:** Georgia Power calculated a capacity value of [REDACTED].[[27]](#footnote-27) No analysis was included for single-axis or dual-axis tracking solar.

**Q: How does this compare to other estimates?**

**A:** Georgia Power’s proposed capacity value for solar is significantly lower than all other estimates of which I am aware. For example, PJM’s renewable integration study found that utility-scale solar PV provides 62-72% capacity value;[[28]](#footnote-28) as discussed in the next section, that analysis used the Effective Load Carrying Capability (ELCC) method, which is widely regarded as the most accurate measure of capacity value. Importantly, PJM’s capacity value range includes scenarios in which wind and solar provided up to 30% of PJM’s energy, indicating that the capacity value of renewable resources remains high at even very high penetrations. Solar capacity values in Georgia should be higher than in PJM and many other areas because the Southeast enjoys more hours of sunshine and more direct sunshine than areas at higher latitudes.

As another example, the Colorado analysis discussed above found solar provided $50.60/MWh in value from displacing conventional generating capacity.[[29]](#footnote-29) Other analysis by the National Renewable Energy Laboratory found fixed tilt solar capacity values across more than a dozen sites in the Western U.S. ranged from 50-70%, while single axis-tracking solar ranged from 65-80% capacity value.[[30]](#footnote-30) Georgia Power should have assumed, or at least accounted for some use of tracking solar, as projects with trackers accounted for 79% of solar capacity installed nationwide in 2016 and 2017, as mentioned above.[[31]](#footnote-31) That failure should be corrected in an all-source evaluation.

**Q: What is the relevant geographic area for calculating capacity value?**

**A:** Capacity value is calculated based on a resource’s contribution to the Balancing Authority supply mix, which in the case of Georgia Power is the entire Southern Company operating area, which includes Alabama Power, Mississippi Power, as well as Gulf Power while it remains in the Southern Company Balancing Authority. As a result, even if Georgia Power’s renewable penetration increases dramatically, the total penetration across the Southern Company Balancing Authority is likely to remain lower, so capacity values are likely to remain high. In 2018, solar provided 1.875% of Georgia’s generation, with 2,439 GWh out of 130,061 GWh of total generation coming from utility-scale and distributed solar.[[32]](#footnote-32) Similarly, solar accounted for only 397 GWh out of 144,989 total GWh in Alabama, for a combined solar share across Alabama and Georgia of only 1%.

For comparison, PJM’s renewable integration study shows that renewable capacity values are still high with renewable energy providing up to 30% of energy on its system. Because Georgia Power’s and Southern Company’s wind and solar penetration is much lower than that, it can add large amounts of renewable resources without experiencing a significant drop in capacity value.

**Q: How have renewable resources performed during recent extreme cold weather events?**

**A:** In 2019, 2018, 2014, and 2011, significant parts of the country experienced extreme cold weather events. During all of these events, renewable output has remained high while other generating resources have experienced failures. Specifically, PJM wind output was high during the Polar Vortex event earlier this year,[[33]](#footnote-33) wind output remained high in PJM and the Northeast during the 2018 Bomb Cyclone,[[34]](#footnote-34) wind output was high as a number of regions experienced extreme cold across several events in 2014[[35]](#footnote-35) including the Polar Vortex,[[36]](#footnote-36) and wind earned accolades from the Texas grid operating for helping to keep the lights on during a 2011 cold snap.[[37]](#footnote-37)

SPP data show strong wind output during SPP’s peak winter demand, with wind output typically in excess of 50% capacity factor during the winter peak demand.[[38]](#footnote-38) Similarly, ERCOT data show a 43% of nameplate capacity contribution from coastal wind resources and 20% from non-coastal wind during winter peak demand.[[39]](#footnote-39)

**Q:** **Do other Georgia Power documents accompanying the IRP filing show high renewable output during winter demand periods?**

**A:** Yes. The IRP Reserve Margin Study found that the studied fleet of renewables reduces the winter reserve margin need by 2.35 percentage points relative to the summer reserve margin.[[40]](#footnote-40) In contrast, Georgia Power found other resources increase the winter reserve margin relative to the summer reserve margin, with natural gas combined cycle increasing the required winter reserve margin by 1.26 percentage points, and oil and gas combustion turbines increasing it by 2.77 percentage points. Georgia Power’s Reserve Margin Study also shows that solar contributes significant output during both summer and winter peak demand periods, with summer output at between roughly 38-70% of nameplate, and winter output at between 13% and 20% of nameplate.[[41]](#footnote-41) The solar RECB analysis finds [REDACTED].[[42]](#footnote-42) It makes sense that solar resources will have higher output during winter peak demand periods, as solar photovoltaic panels, as well as inverters and other associated power electronics, operate at significantly higher efficiency when they are cooled by low ambient temperatures and wind speeds.

**Q: Have other grid operators assessed the value of renewable resources for increasing resilience, particularly during extreme winter weather?**

**A:** Yes. Last year, the New England grid operator released a report examining resilience to extreme winter weather under a range of generation mixes for the mid-2020s, and the scenarios with the highest shares of renewable generation proved to be the most reliable. In fact, three of the four of the most reliable portfolios were high renewable scenarios.[[43]](#footnote-43) PJM’s 2017 resilience analysis similarly found that scenarios with very high levels of renewables were among the most resilient to extreme weather, particularly winter cold snaps.[[44]](#footnote-44) PJM’s study also discussed a range of other events that can cause outages at conventional power plants, like flooding, drought and high temperatures restricting cooling water availability, and coal barge and rail congestion. Renewable resources like wind and solar PV are generally resilient to such disruptions because they are not dependent on deliveries of fuel or cooling water.

**Q: Is the capacity value of renewable resources adequately accounted for in Georgia Power’s winter reserve margin analysis?**

**A:** No. As I explain in the next section of my testimony, Georgia Power’s proposed adoption of a higher winter reserve margin is not the best approach for addressing concerns about correlated failures of conventional generators during extreme winter weather. Conducting a resource adequacy analysis for two seasons is better than a single season, but as explained below, a better solution is to use an Effective Load Carrying Capability (ELCC) analysis or other statistical analysis that accounts for correlated failures of conventional generators to capture resource adequacy concerns across the entire year and to fairly and accurately measure the contributions of all resources.

The Effective Load Carrying Capability (ELCC) method is widely viewed by NERC and other experts as the most accurate method of assessing the capacity value of resources.[[45]](#footnote-45) This method calculates the loss of load probability in each hour, and then measures the contribution each resource, group of resources, or entire fleet of resources makes towards reducing that probability. Like other capacity value calculation methods, the result is typically expressed as a percent indicating the share of a resource’s nameplate capacity that can be counted of for meeting system demand.

An annual ELCC calculation method also correctly shows that wind and solar resources provide more capacity value than is commonly estimated using seasonal methods. For example, an annual ELCC method accounts for how renewable resources have made important contributions during multiple recent winter shortage events driven by the failure of conventional generators due to extreme cold, including the Polar Vortex events this year and in 2014 and the Bomb Cyclone last winter, as discussed above. An ELCC method also accounts for the reliability contribution of resources during shoulder periods when conventional generators are down for scheduled maintenance. This is particularly important due to the increasing frequency and magnitude of unexpected weather events, such as extreme heat or cold during spring and fall when many conventional units are offline for scheduled outages. Fortunately, wind and to a lesser extent solar output is typically very high during these spring and fall shoulder periods.

**Q: What factors cause Georgia Power’s estimate for renewable capacity value to be so low?**

**A:** A primary problem appears to be that Georgia Power’s Renewable Cost Benefit (RCB) analysis incorrectly reduces the capacity value of wind and solar to account for forecast error and frequency regulation needs.Reducing the capacity value of renewables to account for frequency regulation and forecast error does not make sense, as the impact of variability and uncertainty on wind and solar’s capacity value is already accounted for in the hourly output analysis that determines the capacity value of those resources. Accounting for it in both places is double counting. Moreover, those operating reserves are provided by existing resources, so the capacity already exists and no new capacity must be built to accommodate wind and solar’s added variability and uncertainty. This error significantly reduces the capacity value of wind and solar, with wind’s capacity value being reduced by [REDACTED] for frequency regulation and [REDACTED] for forecast error,[[46]](#footnote-46) and solar’s being reduced by [REDACTED] for frequency regulation and [REDACTED] for forecast error.[[47]](#footnote-47) Georgia Power also incorrectly adds a support capacity capital cost to wind, increasing its cost by [REDACTED] in net present value terms.

**Q:** **Are there other errors in the RCB analysis?**

**A:** Yes. Georgia Power calculates extremely high production cost impacts for renewable forecast error and frequency regulation, much higher than other estimates.[[48]](#footnote-48)

Georgia Power’s estimates for wind and solar forecast error are extremely high for several reasons. Georgia Power assumes the use of a persistence forecast method in which wind or solar output is assumed to be the same as it was the hour prior, which introduces two separate problems. First, renewable forecasting methods using weather or statistical methods can significantly improve upon persistence forecasts at the 1-hour ahead time interval, as a recent NREL paper documented.[[49]](#footnote-49) Other NREL analysis found 2% forecast error 4 hours ahead, much lower than Georgia Power’s estimate for hour-ahead forecast error, and hour-ahead forecast error should be significantly lower than four-hour ahead forecast error.[[50]](#footnote-50)Second, most grid operators use persistence forecasts based on the level of renewable output at 10 minutes or less before the operating interval,[[51]](#footnote-51) which greatly reduces forecast error relative to hour-ahead persistence forecasts because wind and solar output deviates much less over the course of 10 minutes than it does over the course of an hour.[[52]](#footnote-52)

Several additional errors could be inflating the forecast error and frequency regulation impacts, though Georgia Power does not provide sufficient data for a reader to determine if it is making these errors. First, it is not clear if Georgia Power is correctly netting out the impact of wind and solar variability and uncertainty against all other sources of variability and uncertainty on the power system. Because renewable variability and uncertainty typically have little to no correlation with the far larger variability and uncertainty in electricity demand and conventional generator output deviations, most renewable variability and uncertainty is typically canceled out, resulting in only modest increases in total system variability and uncertainty.

Second, Georgia Power should have conducted the reliability analysis for the entire Southern Company Balancing Authority footprint, not just the Georgia Power footprint. As noted below, geographically diverse wind and solar resources have much less variable and uncertain output than those in a highly concentrated area, as the impact of clouds and other local meteorological phenomenon are mostly canceled out. Third, it is not clear if Georgia Power properly accounted for the inherent geographic diversity provided by adding new wind and solar generation, due to the fact that it is physically impossible to build new generators on top of existing ones. These potential errors were included in a National Renewable Energy Laboratory’s (NREL) list of common errors in utility renewable integration studies.[[53]](#footnote-53) Georgia Power does not provide sufficient explanation to demonstrate that it is not making these errors, so its analytical methods deserve further scrutiny.

**Q: Can other strategies be used to reduce the operating reserve needs associated with higher renewable penetrations?**

**A:** Yes, several recent reports have demonstrated that wind and solar generation can cost-effectively provide operating reserves, flexibility, frequency response, and other reliability services, not only meeting the additional reserve needs they introduce but also the total system variability and uncertainty associated with demand, conventional supply, other sources.[[54]](#footnote-54) In some regions like Colorado and Texas, wind and solar are providing these services today.[[55]](#footnote-55)

**Q: Does Georgia Power account for how recent and expected technology improvements have improved the reliability services contributions of renewable resources?**

**A:** No. Georgia Power did not evaluate the costs and benefits of tracking solar technology, even though this accounts for vast majority of installations going forward, as noted elsewhere in my testimony. Accounting for the use of tracking technology would have significantly increased the energy and capacity value of solar, and reduced its variability and uncertainty.

With FERC Order 827 in effect, wind and solar now provide reactive power and voltage control using their inverters and associated power electronics. Wind and solar can potentially even provide reactive power and voltage support when they are not producing active power, such as solar plants pulling power from the grid at night to provide reactive power or voltage support to the grid using their inverters.

Renewable resources are now capable of providing the reliability services traditionally provided by conventional generators.[[56]](#footnote-56) That wind and solar resources are now competitive with conventional resources on not only cost but also reliability services contributions is further impetus for Georgia Power to move to an all-source solicitation, evaluation, and procurement approach, as outlined at the end of my testimony.

**Q: How can technology improvements and deployment choices ensure that wind and solar retain their economic value at higher penetrations?**

**A:** One of the most important strategies for increasing power system reliability has always been diversity in both the geographic dispersion and type of generating resources. A diversity of renewable resources will provide Georgia Power with greater economic and reliability value than a portfolio that lacks geographic diversity or is heavy reliant on a single resource. This is because different resources tend to have less-correlated or even negatively-correlated output profiles, so that one is available when the other is not. Georgia Power’s planning should account for the ability of solar and wind resources to work together to build a more cost-effective generation portfolio. Solar and wind complement each other because their output profiles tend to be strongly negatively correlated. Solar’s high daytime and summer output complement wind’s tendency to produce more at night and during the fall, winter, and spring in most regions. As a result of that complementarity, national laboratory analysis of California’s power system found that the value of solar PV at a 10% penetration is increased by $7.40/MWh if wind also provides 10% of energy.[[57]](#footnote-57) This is because the combination of wind and solar provides greater capacity value, reduces morning and evening output ramps, and ensures a more constant supply of energy. PJM’s renewable integration study also confirmed that due to these complementarities, wind has the highest capacity value in scenarios with more solar deployment, and solar capacity value is higher in scenarios with more wind.[[58]](#footnote-58)

Geographic diversity is also an important strategy for obtaining a diverse output profile and higher capacity value from renewable resources. The fundamental reason is that weather and climate at one location in the region is typically very different from, or at least not perfectly correlated with, weather at a distant location in the region.[[59]](#footnote-59) For example, it may be cloudy and windy in Kansas, while it is sunny and calm in Georgia at the same point in time, so the different patterns of solar and wind output from those locations cancel each other out and increase the aggregate capacity value of the renewable fleet. Due to this effect, the analysis of California’s power system mentioned above found that increasing the geographic diversity of the wind fleet increased its economic value by $2.50/MWh at a 20% wind penetration, $4.90 at a 30% penetration, and $10.60/MWh at a 40% penetration. As a result, Georgia Power should ensure its planning process is accounting for geographic and resource diversity to maximize the value renewable resources provide to its customers.

As one example of how geographic diversity can increase the economic value of renewable resources at higher penetrations, solar resources in western SPP can make valuable contributions to the geographic diversity of Georgia Power’s fleet, as their output profile is shifted nearly two hours later than solar resources in the Southeast. SPP solar resources would contribute significant capacity value to Georgia Power due to their high output during the Southeast’s late afternoon and even early evening peak demand periods, as well as helping to make morning and evening solar output ramps more gradual, spreading midday peak generation over more hours, and smoothing out the impact of even the largest weather systems. To the extent Georgia Power’s planning processes observe declines in the value of renewables at higher penetrations, the Company should pursue resource and geographic diversity to counteract those declines.

**Q: What impact is technology having on the output, and economic and capacity value, of renewable resources?**

**A:** Wind and solar capacity factors are increasing significantly. Wind capacity factors have increased from 31.6% for projects installed in 2011 to 42.5% for 2016 projects, mostly due to the use of larger turbine blades, the use of taller towers in some regions, regional shifts in deployment, and general progress in technology and siting.[[60]](#footnote-60)

Average cumulative solar PV capacity factors to date have increased from 23.7% for 2011 vintage projects to 26.8% for 2016 vintage projects. The primary factors are that the share of the annually installed capacity using trackers has increased from 50% to 78%, while Inverter Loading Ratios (the proportion of DC solar module capacity to the AC capacity of the inverter) also increased from 1.19 to 1.33.[[61]](#footnote-61) The increase in capacity factor would have been even larger, but 2016 projects were installed in locations with about 1% lower solar resources on average than those in 2011 due to regional shifts in deployment.

The technological advances that are increasing the capacity factor of wind and solar resources also tend to increase their capacity value and energy value. This is because technological advances like the use of trackers and higher Inverter Loading Ratios for solar PV, and taller towers and longer blades for wind, increase the capacity factor of those resources by increasing their output in hours when they were not at maximum output.[[62]](#footnote-62) Those hours tend to coincide with hours when Georgia Power electricity demand is at or near its peak, as in Georgia peak electricity demand typically occurs during late afternoons during the summer, when solar and wind plants are not typically producing their maximum output. As a result, technological advances that are increasing wind and solar capacity factors are also increasing their capacity value and the economic value of the energy they provide.

As mentioned above, these technological advances also tend to reduce the variability and uncertainty in output, as the renewable generators spend more time at maximum output. European analysis confirms that technologies that are increasing the capacity factor of renewable resources are yielding even larger increases in their economic value to the power system.[[63]](#footnote-63)

**Q: What impact will battery storage have on the economic value of renewables, particularly solar?**

**A:** Battery storage appears poised to play an increasingly important role in meeting power system reliability needs.[[64]](#footnote-64) This includes providing capacity to meet power system peak electricity demand, as well as providing flexibility and other needed reliability services. Capacity and flexibility are needed by the power system regardless of the generation mix, but adding storage to provide those services can help facilitate the integration of renewable generation as storage can charge when renewables are abundant and discharge when they are not, and help to accommodate any increases in power system variability and uncertainty. Storage’s ability to increase the value of renewables is discussed on page 10-73 of Georgia Power’s IRP.

There is a particularly strong complementarity between solar PV and battery storage. First, battery storage is ideally-suited for shifting early afternoon solar output several hours later to meet late afternoon peak demand, and also helping to address morning and evening ramps in solar output. Analysis of the California power system shows that, by increasing the energy and capacity value of solar and providing needed flexibility, battery storage increases the value of solar PV by $3.30/MWh at a 10% solar penetration, $8.40/MWh at 20% solar, and $19.70/MWh at 30% solar.[[65]](#footnote-65)

There are also synergies by which solar increases the capacity value of storage, facilitating storage deployment and thus further increasing the capacity value of solar. By producing a large amount of energy during the early to mid-afternoon, solar PV tends to reduce the duration of system peak demand periods, increasing the value of shorter-duration energy storage resources for meeting peak demand. Georgia Power’s RECB solar analysis shows that [REDACTED] for fixed solar installations, and tracking solar projects should have even higher output during those hours. Thus, solar shortens the peak demand period, allowing batteries with limited duration to better contribute throughout the peak demand period.

**IV. Rather than increasing the winter reserve margin, Georgia Power should use a consistent framework for evaluating generators’ capacity value contributions**

**Q: Why does Georgia Power propose to increase its winter reserve margin?**

**A:** Georgia Power offers five reasons why it needs to increase its winter reserve margin: **“**(1) the narrowing of the difference between summer and winter weather-normal peak loads; (2) higher volatility of winter peak demands relative to summer peak demands; (3) cold-weather-related unit outages; (4) the penetration of solar resources; and (5) increased reliance on natural gas.”[[66]](#footnote-66)

**Q:** **Are those concerns best addressed through a higher winter reserve margin?**

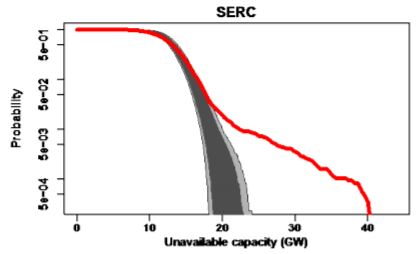
**A:** No. To ensure a more accurate calculation and equitable allocation of capacity value, Factors 3, 4, and 5 should be addressed through reduced capacity value of supply, not increased reserve margins. Georgia Power should calculate the true capacity value contributions of renewables and conventional generators, using ELCC or another method that accounts for the correlated outages of conventional generators. Factors 1 and 2 can be better addressed by better setting the peak demand estimate, and not by adding a reserve margin on top of that. To the extent Factor 2 refers to a long-term average for winter peak demand not capturing significant inter-annual variability, it may make sense to increase the reserve margin to address that. Regardless, because nearly all of the factors Georgia Power is concerned about relate to correlated outages of some types of generators, a better method would be to reduce the capacity value of those generators to account for their correlated outages.

**Q: Are correlated outages of conventional generators due to equipment failures, fuel supply issues, and other factors accounted for in traditional capacity planning methods?**

**A:** No. System planning methods are typically based on the incorrect assumption that conventional generator outages are random, uncorrelated events. For example, if data indicates that each unit of a certain type of resource has a forced outage 10% of the time, then the standard method predicts that the odds of two units having an outage at the same time are only 1% (10% times 10%). However, recent operating experience in Georgia and elsewhere demonstrates that that prediction is invalid, as extreme winter weather and other events can cause many conventional generators to fail simultaneously through correlated outages due to equipment failures, fuel supply interruptions, and other problems, also known as “common mode” failures. Increasing the reserve margin as Georgia Power has proposed is simply a work-around to compensate for the flawed assumption in resource adequacy analysis that generator forced outages are independent uncorrelated events. As a recent paper explained:

*Our findings highlight an important limitation of current resource adequacy modeling (RAM) practice: distilling the availability history of a generating unit to a single value (e.g. EFORd, the equivalent forced outage rate during times of high demand) discards important information about when units in a power system fail in relation to one another. Only by incorporating the full availability history of each unit into RAM can we account for correlations among generator failures when determining the capacity needs of a power system. We strongly recommend that system planners incorporate correlated failure analysis into their RAM practice.[[67]](#footnote-67)*

NERC data used in the Carnegie Mellon paper’s analysis demonstrates that conventional generators experience common mode correlated outages many times more frequently than is predicted under the assumption that individual plant outages are uncorrelated independent events. As shown below, in the SERC region that includes Georgia, actual winter generation outages (red line) are roughly twice the level of outages that would be expected under the assumption that generator outages are uncorrelated independent events (gray area), with about 15-20 GW more outages than expected.[[68]](#footnote-68) Only in the Reliability First Corporation region (which covers much of the Great Lakes and Mid-Atlantic area) did actual winter outages exceed the level of expected outages by a larger margin, with 50 GW of outages versus an expectation of 20-25 GW.



**Q: Do the data indicate which resources are experiencing correlated failures?**

**A:** Yes, the data show that correlated forced outages tend to occur more frequently at certain types of conventional generators, with simple cycle gas generators experiencing the highest correlated outage rate in SERC.[[69]](#footnote-69) Rather than increasing the reserve margin, a more accurate and fair way to account for the correlated outages of certain resources would be to reduce those resources’ capacity value. The correlated output patterns of wind or solar resources are typically accounted for in calculating their capacity value, so failing to account for correlated outages of conventional generators overstates their capacity contributions relative to renewable resources.

**Q:** **Aside from overvaluing conventional generators’ capacity value relative to alternatives, what harm can result from failing to account for correlated conventional generator outages?**

**A:** Accurately assessing the capacity value contributions of resources is critical for ensuring that Georgia Power’s planned resource portfolio is adequate to meet reliability needs. Overestimating the capacity value of new gas generation not only results in an economically suboptimal resource mix, but it can also cause electricity supply to fall short of demand. Building more gas generating capacity to meet a higher winter reserve margin is an exercise in futility if the fundamental factors causing correlated forced outages of gas generation during winter peak demand periods are not addressed. This is particularly true if new gas generators are susceptible to the same outage causes as the existing fleet, like dependence on the same congested gas pipelines.[[70]](#footnote-70) Georgia Power would have to continue chasing ever-higher reserve margins if its solution for meeting a higher reserve margin is building more gas resources that are susceptible to the same correlated outages as the existing fleet. In contrast, adding renewable generation that is not affected by fuel delivery and other constraints reduces risk and increases resilience by diversifying the generation mix. This finding has been confirmed by high levels of renewable output during recent extreme cold weather events and the resilience analysis conducted by PJM and the New England grid operator, as discussed above.

**Q: Did the Carnegie Mellon paper assess the value of adopting seasonal resource adequacy metrics, as Georgia Power has proposed?**

**A:** Yes, the paper concluded that the use of seasonal resource adequacy metrics failed to adequately address the challenge of correlated outages:

*We found little evidence for seasonal patterns in unscheduled unavailable capacity in the eight NERC regions. Instead we found that large unavailable capacity events can occur in any season …These findings suggest that a seasonal resource adequacy construct, whereby an availability statistic is calculated for each unit in each season, may not meaningfully reduce resource adequacy risk. However, these conclusions may change with a longer study period.[[71]](#footnote-71)*

**Q: What methods can be used to analyze the impact of correlated outages of conventional generators?**

**A:** As discussed in the preceding section, the Effective Load Carrying Capability (ELCC) method is widely viewed by NERC and other experts as the most accurate method of assessing the capacity value of resources, as it accounts for the contribution of resources during potential electricity shortage periods across the entire year and also accounts for correlations in generator output and outages.[[72]](#footnote-72) Even without using a full ELCC method, statistical methods for calculating correlation and its impact on joint probability can be readily applied to determine the impact of correlated generator outages on the capacity value of a portfolio of resources and a specific type of resource.

**Q: Do the conventional generator forced outage rates used in Georgia Power’s Reserve Margin analysis appear reasonable?**

**A:** No, Georgia Power’s figures for equivalent forced outage rate, or EFOR, as replicated below appear quite low. For most fossil resources, PJM’s data show forced outage rates that are significantly and in some cases many times higher than those indicated below, with nuclear at 1.0%, coal at 11.7%, gas steam at 11.0%, combined cycle at 2.5%, and combustion turbines at 4.8%.[[73]](#footnote-73) This should be corrected in an all-source evaluation.

|  |  |
| --- | --- |
| **Unit Class** | **EFOR (%)** |
| Nuclear | [REDACTED] |
| Coal | [REDACTED] |
| Gas Steam | [REDACTED] |
| Combined Cycle | [REDACTED] |
| CTs | [REDACTED] |
| Total System | [REDACTED] |

**V. Georgia Power’s capacity-driven planning misses opportunities to economically replace existing generation**

**Q: What do you mean by capacity-driven planning?**

**A:** In its IRP, Georgia Power primarily evaluates the net benefits of resource additions when there is a need for new capacity to meet peak electricity demand. As Georgia Power’s IRP explains, “When developing the IRP, the Company begins by establishing reliability criteria, which are thoroughly reviewed in the Reserve Margin Study in Technical Appendix Volume 1. The Company then applies these criteria to the demand and energy forecasts to determine the amount of capacity that is required to reliably meet forecasted conditions.”[[74]](#footnote-74) Georgia Power further explains that its planned resource additions are heavily driven by capacity needs: “The planned and committed resources in this IRP provide for adequate reserves until 2028 at which point the Company is currently projected to have a capacity need. However… the Company may encounter a capacity need prior to 2028 due to potential unit retirements. To satisfy capacity needs and maintain reliable electric service, the Company plans to issue two capacity-based RFPs.”

**Q:** **What are the problems with capacity-driven planning?**

**A:** There are a number of problems with this approach, including that it seems to have contributed to Georgia Power’s decision not to include renewable resources as a selectable option in its economic modeling. As the IRP notes, “It is important to note that recent and proposed renewable additions are selected based on their ability to provide projected energy cost savings to customers, not to specifically meet a capacity need.”[[75]](#footnote-75)

First and most importantly, capacity-driven planning only shows a need if the power system needs new capacity to meet peak demand, and those opportunities have been limited due to stagnant demand growth over the last decade. As a result, capacity-based planning often misses the opportunity for new resources, like renewable generation, to cost-effectively replace existing energy and capacity. For example, looking holistically at the value of energy, capacity, and other services and comparing the cost and benefits of alternatives like renewables to the current fleet could allow the earlier retirement of existing generators to the net benefit of customers.

Second, generating capacity capital and fixed operating costs generally account for a significantly smaller share of total system costs than energy-related production costs, so it does not make sense to drive resource mix decisions based on capacity expansion needs. For example, in PJM, energy costs are three times greater than capacity costs.[[76]](#footnote-76) In economic evaluations of resource mix options, energy and capacity costs should be given weight proportional to their impact on customer costs. Capacity-driven planning’s focus on generation resource adequacy may also distract from investments that can better improve customers’ electric reliability and resilience. For example, transmission and distribution infrastructure account for more than 99 percent of customer electric outages, with generation supply accounting for a fraction of one percent of outages.[[77]](#footnote-77)

An additional problem is that capacity-driven planning is less likely to select renewable resources. This is particularly true if the analysis understates renewable resources’ capacity value contributions or if conventional generators’ correlated outages are not accounted for, as explained above. Old methods for assessing capacity contributions are likely to be particularly challenged as new resources become available and the generation mix changes. Energy-limited resources like battery energy storage provide significant capacity value, but many traditional measures or requirements of capacity value, such as arbitrary duration rules requiring a resource to be able to provide power for 4 or 10 hours, fail to accurately account for that contribution. Hybrid resources that incorporate battery storage further complicate that analysis.

Emerging concerns about conventional generation correlated forced outages are also testing the accuracy of old capacity value assessment methods, as noted above. Using the traditional assumption that conventional generator forced outages are random uncorrelated events can drive additional investment in resources with the highest correlated outages, without addressing the fundamental factors causing the forced outage of those resources during winter peak demand periods. In contrast, adding renewable generation that is not affected by fuel delivery and other constraints reduces that risk and increases resilience by diversifying the generation mix, but that benefit will not be accounted for if the underlying risk of correlated outages is not captured by the capacity valuation method. Fortunately, methods like ELCC that account for correlated changes in generation output allow for accurate and fair assessments of resources’ capacity value.

The final major problem with capacity-driven planning is that, as renewable penetrations increase, attributes like flexibility and other reliability services are likely to be far more important than capacity. However, capacity-based planning treats all capacity MWs the same, and does not distinguish resources’ different ability to provide flexibility and other reliability services. For example, a gas combustion turbine can be operated very flexibly with quick start and stop times, while a coal generator can take days to start up or shut down, has a relatively high minimum output, and can only gradually change its output. However, current capacity-based planning does not distinguish among those very different operating characteristics and the ability to provide needed reliability services, viewing a coal MW the same as a gas combustion turbine MW.[[78]](#footnote-78)

**VI. Proposal for a new all-source evaluation and procurement**

**Q: How can Georgia Power address the problems you have identified above?**

**A:** Instead of issuing a Request for Proposals (RFP) for capacity, Georgia Power should conduct an all-source solicitation, evaluation, and procurement process that explores many possible combinations of existing and new resources to minimize the net present value cost of all energy and capacity costs. The analysis could also include a risk averse treatment of fuel price risk. The analysis would ensure hourly load, flexibility, and other reliability needs would be met, accounting for correlated output patterns of both renewables and conventional generators, and the cost of any resource inadequacy in any hour of the year would be accounted for. Statistical methods for calculating joint probability and covariance can be readily applied to determine the impact of correlated generator outages on a resource type’s capacity value.

**Q: Have other utilities used all-source RFPs as replacements for capacity-driven RFP’s?**

**A:** Yes. In Colorado, utility Xcel Energy has conducted all-source RFPs. The most recent solicitation yielded 430 responses, of which 350 were for wind, solar, and storage resources, including hybrid resource combinations.[[79]](#footnote-79) That included over 100 GW of renewable and storage offers, with record low prices for the renewable and storage offers. Wind and wind hybrid projects offered an average price of around $20/MWh, while solar and solar hybrid projects offered an average of around $30/MWh, indicating that many projects offered prices significantly below those levels.

All-source procurements have also been successfully used in California, New York, and Arizona.[[80]](#footnote-80) Indiana utility NIPSCO used an all-source RFP for its 2018 IRP, “which concluded that wind and solar resources were shown to be lower cost options for customers compared to other energy resource options” and resulted in the procurement of 800 MW of new wind capacity.[[81]](#footnote-81) As renewables, energy storage, and other new resources become increasingly competitive with conventional resources on both cost and reliability contributions, failing to competitively evaluate all resources can result in massive excessive costs for customers.

**Q: What data should be included in Georgia Power’s all-source analysis?**

**A:** The all-source evaluation should incorporate market-based offers gathered through a Request for Proposals or similar solicitation, and then Georgia Power should procure the quantity and type of new generation that will optimize net benefits for its customers. The cost-benefit analysis should be revised to include this market-based information, as well as the revisions to economic and reliability assumptions discussed in sections II and III of my testimony.

**Q: Does this conclude your testimony?**

A: Yes.

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6. <https://www.awea.org/resources/publications-and-reports/market-reports/2018-u-s-wind-industry-market-reports> [↑](#footnote-ref-6)
7. IRP at 8-58 [↑](#footnote-ref-7)
8. <https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf>, page 10 [↑](#footnote-ref-8)
9. [https://atb.nrel.gov](https://atb.nrel.gov/), 2018 [↑](#footnote-ref-9)
10. <http://www.startribune.com/cost-of-adding-new-wind-solar-energy-continues-to-fall-in-minnesota-report-says/507000642/> [↑](#footnote-ref-10)
11. <https://atb.nrel.gov/> [↑](#footnote-ref-11)
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21. IRP Mix Study [↑](#footnote-ref-21)
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46. IRP Wind Analysis, page 14 [↑](#footnote-ref-46)
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