Southern Company Comments

Draft NARUC Manual on DER Compensation

Southern Company and its retail electric operating subsidiaries, Alabama Power, Georgia Power, Gulf Power and Mississippi Power appreciate the opportunity to provide comments on the draft "NARUC Manual on Distributed Energy Resources Compensation" prepared by the NARUC Staff Subcommittee on Rate Design, and released on July 21, 2016.

In general, we believe the concepts and language in this report are fair and representative of the issues and challenges. We do have some concerns and suggested improvements for the document which are summarized below. Any questions concerning our response may be directed to Bruce Edelston (<u>bsedelst@southernco.com</u>), Vice President of Energy Policy.

Specific Comments of Southern Company

1. Page 6.

The draft Manual states – "The basic purpose of rate design is to implement a set of rates for each rate class – residential, commercial, and industrial – that produces revenues to recover the cost of serving that rate class."

In practice, rates are not based on an individual customer's cost to serve, but rather similar customers are accumulated into rate classes, and the total cost to serve all of the customers in that rate class is allocated equally across all of the customers in that rate class." Based on this statement, which is a defining principle of the manual, an assertion can be made that DER customers who have generation, storage or other self-controllable loads should be in a different rate classification than the traditional full requirement, firm load customers. In essence, these DER customers are partial requirements customers with a fixed and variable component of their loads.

Rates for this new customer class should be based on separate cost of service and revenue requirements for the class to avoid cross subsidization between classes, and to ensure that cost-causation principles are followed. In addition, the intermittent and variable loads that result from customer-owned generation make utility planning and investment decisions more difficult, and create different risks and costs than typical non-generating customers. Particularly in regions such as ours where utilities still have an obligation to serve all customers within assigned franchise territories, utilities must build generation, transmission and distribution to meet the maximum load potential. If customer distributed resource owners place additional costs on the system but are not part of a separate rate class that

pays those additional costs, than the burden falls on all customers within the class. In many cases the non-participants will be low use and low income customers. If these partial requirements DER customers desire to have their non-firm load served, they should have to pay a premium or actual costs to cover the additional incremental expense. Utilities should not be required to serve non-firm loads under the same rates, terms and conditions as firm loads.

2. Page 30.

The draft Manual states – "It can be argued that the majority of a utility's costs are fixed. It can also be argued that the majority or entirety of a utility's costs are affected by the way customers utilize the service provided, making the costs variable. The two opinions vary mainly in the time horizon considered. Those who feel the appropriate time horizon is the short-term tend to identify more costs as fixed. Those who feel the appropriate time horizon is the long-term tend to identify more costs as variable. There are additional considerations related to historical responsibility for long-term investments made to serve the customers and usage that were projected at the time they were made."

While we agree that the time period being considered matters, we believe that the draft Manual fails to recognize that there are differences in the manner in which planning is conducted for distribution systems versus traditional central station generation and transmission systems. Central station generation and transmission systems have been and continue to be planned on a long term basis out of necessity – they are both long lead-time assets and long-life assets. Where there are real opportunities to develop alternatives such as: demand response, energy efficiency programs, distributed generation and others that allow us to delay new central station generation and/or transmission projects, than there is an argument that the value of those delays should be credited to the alternative. This value can be calculated with relative certainty and included in avoided cost capacity payment calculations. In market regions, the market clearing price for capacity could be used. However, distribution system planning has quite different characteristics. In fact, long-term planning for distribution is considered to only be 18 to 36 months in the future. And distribution must be planned to peak the peak load on individual feeders. Where in bulk system (generation and transmission planning), it can be assumed that on average, DER will be available as planned for, with distribution feeders, such "average" assumptions can't be made, and the feeder must be designed assuming intermittent generation is not available at the customer's peak usage point. There are several additional reasons why we can't assume that DER will reduce capacity needs for the distribution system:

 The peak loads for distribution feeders can be summer peaking one year and winter peaking the next;

- Depending on the load mix (of customer end-uses) of a feeder, its peak may occur on any day at any hour; thus, the occurrence of the peak can be at a time when power production of a given DER technology is typically unavailable;
- Loading on distribution feeders is not constant and can change frequently and very rapidly; and,
- Distribution feeders are frequently reconfigured to address loading conditions or feeders are combined or modified as new distribution substations are added or new customers appear on a feeder.

Due to all of these uncertainties, we do not believe that the ability to predict avoidable costs in the distribution system is extremely problematic and could lead to higher overall costs if distribution system capacity credits were offered.

3. Page 31.

We suggest revising one sentence which currently reads: "DER can also reduce or avoid investment in capacity". We believe that the "can" should be changed to "may". This change is consistent with a sentence two paragraphs down: "..., future investment in capacity <u>may</u> (*emphasis added*) be reduced." In addition the paper says that future investment in Distribution capacity may be reduced. For intermittent resources at least we believe there is no deferred distribution capacity as discussed above. This assertion was more fully discussed in a paper prepared by Georgia Power for a recent Notice of Inquiry Workshop on the value of solar held by the Georgia PSC last year and also was a major part of Georgia Power's just concluded Integrated Resource Plan proceedings. That paper, "A Framework for Determining the Costs and Benefits of Solar Generation in Georgia," is available at <u>http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=161828</u> in the PD Vol 1, 5 PD RENEWCOST BEN folders, Document: 1-PD GPC Framework.

4. Pages 34 and 49.

The draft Manual asserts that utility risk is reduced either by higher fixed charges (pg 34) or by adding demand charges (pg 49). This may be an incorrect assertion. Although the risk due to volatility of revenues associated with fixed costs may be reduced, the overall risk is not reduced, but instead it is shifted to other risk factors. Risks would be reduced only if customer usage (and thus revenues) did not change in moving from rates with mostly variable charges to rates including demand charges. There is no guarantee that a utility will keep the same number of customers or that demand rate customers will not reduce their demand and/or energy use (just as customers are more likely to reduce energy use without any consideration of demand under mostly variable rates). In fact, one would expect that demand rate customers would shift their usage to lower cost periods, resulting in reduced revenues to the utility. The only real method for reducing utility revenue risk is by using formulaic decoupling.

5. Page 34.

The draft Manual's description of the history of fixed charges in utility rates we fear denotes a strong bias (perhaps unintentionally) against the use such charges. There should be a rework of the second paragraph under Subsection "C." The topic does have a long history (see, for example, Havlik: Service Charges in Gas and Electric Rates, c 1938), but the story is remarkably consistent throughout the industry's history-- utilities have always tried to better align its prices with its costs, albeit not always successfully. We are not seizing an opportunity now to do something untoward or unnecessary. It is a fact that the industry is changing, and regulatory principles need to adopt to conform to those changes. Historical practices under an industry characterized by franchised, exclusive service areas with few customer alternatives may not be relevant today. And while the industry has co-existed with DER under old rate structures for years, many of the issues were simply ignored because the level of inefficiencies and cross subsidies created were not significant. But that is changing as well.

6. Page 35.

The draft Manual comment on page 35 regarding the true value of energy pushed back on utility systems by DG "as available energy" is exactly right.

Pages 50 -53. "1. Considerations in Demand Charges"

We believe this Section on residential demand rates is substantially biased against the use of a demand component in residential rates. We believe that demand charges as part of an overall rate structure are very important to ensure that the costs of serving different customers are paid for by those customers – the cost causation principle once again. But rates that include demand components are also important to address the issue of adequate compensation for the use of the generation, transmission and distribution system for those customers that have installed DER. Demand-based rates have the advantage of being closely aligned with cost causation, in that a utility's peak demand by and large determines the amount of capacity that will need to be provided to serve load. Customers with higher demands create higher costs to the utility. A demand based rate for residential would also help mitigate the cost shifting that can occur between participants and non-participants. We do not think that demand-rates should be eliminated from consideration even with some of the issues cited in the draft Manual. But if rates with a demand component are not acceptable, at a minimum the Manual should continually emphasize the need that rates reflect cost causation to the greatest degree possible. Demand-based rates may be the best way to meet these objectives, but there are other alternatives that can at least get us part way there.

7. Page 50.

The draft Manual tries to address the impact of demand rates on low load factor/low income customers. It is very difficult, if not impossible to equate low income with low load factor customers and at a minimum, empirical evidence with respect to a particular utility's system is important. Second, we don't believe that the assumption that low income customers can't respond to demand prices is correct. We do believe that a change to a demand charge structure would have a larger impact on low load factor customers. This is the effect of demand rates assigning costs to the cost causers, as it is universally understood that lower load factors results in higher costs for the utility. The principle of gradualism should be used to transition customers to new rates that are more reflective of costs.

8. Pages 51-52.

The paper has a negative bias regarding non-coincident peak demand charges. Especially given the difficulty for both customer and utility (both well described in the paper) in implementing the Manual's preferred coincident-peak demand rates. Non-coincident peak demand rates are the standard industry practice for C&I and have been for many years. Non-coincident demand is the allocator used for all distribution level costs in our cost of service studies. Thus, all distribution costs can and should be recovered based on non-coincident peak demand. While easy to understand by the customer and readily implement by the utility, general TOU demand rates use basic time periods as a reasonable proxy for

coincident peak without the difficulties of implementing a true coincident peak demand rate. This method includes the risk of "missing" the coincident peak, because no one knows when the coincident peak will occur until after the fact.

9. Page 54.

The draft Manual addresses price elasticity (and more energy use) under a lower energy charge that would result from a higher fixed charge. While this assertion may be correct, the conclusion is not supportable. For customers to find value in our product is a positive and their use of more of it for their benefit demonstrated the products value to the customer. Given this customer value and need, the utility must invest more to meet the customers' demand. As customers use more, fixed costs are spread further, improving the overall efficiency of the system and putting downward pressure on rates for all customers. This is a macroeconomic picture of efficient pricing. Utilities, no matter how much energy they are producing from fixed capacity resources will still have to meet all applicable environmental standards, and in many cases the extra kilowatt-hours will be produced in off-peak periods from renewable resources.

10. Page 62.

The comment that the timing of reforms should be based on DER penetration and growth was a good one. "For the jurisdictions with low DER penetration and growth, there is time to plan and take the appropriate steps and avoid unnecessary policy reforms simply to follow suit with actions other jurisdictions have taken."