MEMORANDUM

TO	South Carolina Electricity Market Reform Measures Advisory Board
FROM	John Tsoukalis, Kathleen Spees, Johannes Pfeifenberger, Andrew Levitt, Andrew W. Thompson, Oleksandr Kuzura
SUBJECT	**Brattle Responses to Advisory Board Member Comments on Draft Report**
DATE	April 28, 2023

AARP South Carolina

John C. Ruoff, Ph.D., AARP South Carolina, Executive Council volunteer, March 21, 2023

On behalf of its 613,000 members, AARP South Carolina submits the following comments on the Brattle draft market reform study. First, as a preliminary matter, AARP supports measures and reforms to deliver reliable and affordable electrical service to the state's electricity ratepayers. Members of the over-50 community are especially sensitive to unexpected electricity rate increases, power outages, and reliability problems. Indeed, our members in Texas and California have suffered from power interruptions and higher electricity prices caused by the complicated new RTO-induced structures where no one is clearly in charge of keeping the lights (and air conditioning and heating) on.

AARP commends Brattle for identifying a regional transmission organization's regional dispatch and planning benefits but submits that much of the potential costs and detriments of such a development still need to be vetted. AARP does not believe South Carolina electricity ratepayers would currently benefit from an RTO. We base our comments on the realities of RTOs after 25 years in states that have them.

In a word, they are a work in progress. Their dispatch algorithm is now out of synch with states that favor the dispatch of the cleanest (not most economical) resources. Worse, RTOs force states to pay to upgrade each other's grids. Those upgrades are often of dubious value to other states. Further, they are beholden to their voluntary members rather than consumers. Utilities and developers often advance their agendas to the detriment of ratepayers. Finally, they need to consider local alternatives like local storage, local solar, and microgrids that would be more timely and more economical than authorizing the construction of billions in new high-voltage transmission lines from distant states.

The study downplays the development of the new Southeast Energy Exchange Market (SEEM). This voluntary organization includes members from Missouri to Florida, including the Southern Company, which for 25 years has opposed such a regional system. SEEM – which only started on November 1 – should be allowed to work. SEEM can grow into an RTO if needed. Instead of looking at alternatives, South Carolina stakeholders should embrace SEEM. Our specific comments are as follows:

AARP South Carolina is disappointed that the Brattle Study on wholesale market reforms did not incorporate all the costs of being in an RTO. Therefore, their finding of $362 million in savings from regional dispatch ignored:

- Loss of state control and regulatory authority and its impact on reliability and rates.
- Higher utility rates because FERC allows higher rates of return than the Public Service Commission.
- Paying billions to upgrade the grid in neighboring states would raise South Carolina's electricity rates without concomitant benefits.
- Failures of RTOs in Texas, California, and the Midwest to ensure enough reliable supply. RTOs have complex schemes to incent the new generation, which have yet to work out. Clear state regulatory authority and the responsibility of utilities to construct needed new long-term resources is preferable to the decentralized RTO model.
- Costs of the RTO ($500 million per year in operational expenses in some RTOs), paying twice for FERC dues (by the RTO and by the utility), costs of attending the plethora of stakeholder meetings at RTOs and at FERC), and more.

Most importantly, South Carolina does not need an RTO since the nascent Southeast Energy Exchange Market started on November 1. It should be allowed to work, and – if it benefits electricity consumers – it can grow into an RTO.

Suggesting South Carolina should join an RTO in Pennsylvania (PJM) should be dismissed outright. Member states of PJM have struggled to support their state policy goals in an RTO that uses a dispatch algorithm that runs contrary to their state's policy which now favors the dispatch of the cleanest resources.

RTOs are a 1990s idea that has yet to adapt to the clean energy era. The Brattle Study ignored the problems RTOs have encountered since being first rolled out by FERC 25 years ago. There is a reason South Carolina is not in an RTO today, and everything has stayed the same to mandate one.

South Carolina regulators and utilities need more time to attend the plethora of daily meetings held by RTOs. Their influence is diluted by the 12 or more other states in the room. Indeed, RTO MISO once had over 700 meetings per year. RTOs are cumbersome, complicated, and expensive entities to deal with.

RTOs have reliability issues. ERCOT, the RTO serving Texas, has struggled to provide enough reliable and affordable power in recent years. California ISO has had the same problem in California, where the Governor has had to intervene to keep the lights and air conditioning on.

Grid operator MISO has also warned of looming blackouts. South Carolina need not cede such authority to a non-governmental agency regulated by FERC until such problems are rectified.

Our other comments include the following:

Brattle supported retail choice in various forms in its report. Allowing some or all South Carolina customers to pick an alternative supplier is terrible. It has yet to show benefits to residential customers in the states that have tried it. Study after study has found that consumers would be better on the utility default tariff. There is no conclusive evidence that residential electricity customers are paying lower rates in the states that allow it. Allowing industrial customers to pick their supplier could leave remaining customers paying for fixed system costs.

The study also discusses retail rate options. AARP supports voluntary opportunities to help customers manage electricity bills or lower utility costs. We have similar concerns with community choice aggregators (CCAs). Who would build the needed new generation under such a scheme? Who would pay for the costs stranded by customers leaving the system for a CCA? Dilution of responsibility for reliability calls for further study at best.

AARP supports any reforms that avoid a repeat of the VC Summer fiasco. Allowing competitive supply solicitation might be able to keep electricity rates more affordable. Vetting plans in advance through integrated resource planning should keep rates lower.

The study discusses having a third-party administrator manage energy efficiency programs. It needs to be clarified here what problem is being addressed. Utilities typically know their customers better than a third party. Few states have adopted such a scheme, Wisconsin being one of them. We urge further study into this idea.

The study ignores that Duke already operates an integrated system in the Carolinas. Imposing a new structure on top of that may be of dubious value.

In closing, AARP strongly opposes South Carolina joining an RTO like PJM and pursuing any version of retail choice.

Brattle Responses and Clarifications:

- *Texas, California, and several other states have implemented generation divestiture and retail choice for residential customers. We are not recommending South Carolina implement generation divestiture or retail choice for residential customers at this time. Our recommendation is that South Carolina join or create an RTO (or RTO-like regional energy market). This does not require generation divestiture or retail choice for residential customers. Our recommendation is that South Carolina maintain the PSC's full authority to approve rates for all residential customers in the state, approve generation and transmission assets built in the state, and maintain the state's authority to set energy policy. Once the recommended foundational wholesale market reforms are in place, partial retail choice could be introduced or the question of retail choice could be reconsidered at a future time.*
- *Our recommendation to join, form, or integrate with an RTO (or an RTO-like regional energy market) is consistent with maintaining the South Carolina PSC's authority to regulate rates for all residential customers in the state, as well as approve all plans for building new generation and transmission assets, and establishing the return on investments made by investor-owned utilities in the state.*
- *AARP correctly points out that certain RTO models include sharing the costs of some large regional transmission investments if shown to be beneficial to customers in multiple states or necessary to meet reliability criteria. If South Carolina utilities fully joined PJM, including its regional transmission planning process, they would be required to pay some transmission costs for assets in other states. Likewise, certain South Carolina transmission costs in the future could be eligible for cost recovery from customers in other states. If South Carolina pursues the creation of a new RTO in the Southeast, this new RTO would be free to develop new transmission cost sharing rules, including a prohibition on sharing costs across utilities and states or revising cost allocation methodologies to align with states' agreed principles.*

We note that PJM states historically have had a lesser role in transmission cost allocation governance compared to states in other RTO regions, though ongoing reforms are likely to increase the states' role going forward.[1]

- *In the report, we also provide detailed discussion of alternative RTO participation options, such as partial RTO integration (similar to those explored through "Markets+" and "WRAP" in the West), and transition models that should be considered in order to mitigate concerns related to transmission cost allocations and maximize benefits of participating in a regional transmission planning process.*
- *The administrative costs of operating an RTO mentioned in AARP's comments are already included in our analysis of net benefits (see Table ES-1).*
- *We do not recommend retail choice for residential customers at this time in South Carolina. Our recommendation regarding CCAs is for South Carolina legislators to create a pathway to the development of CCAs in the state. However, we note that the ability to implement CCAs in the state would be enhanced by participation in an RTO, and as described in Figure ES-1 this should only be pursued after membership in an RTO. We only recommend that the state consider partial retail choice for large industrial and commercial customers, and agree with AARP's comments that large customers that choose a third-party supplier or communities that choose to form a CCA should pay for their share of fixed costs left on the system and that they must be subject to mandatory resource adequacy requirements to ensure regional reliability (see Table ES-4 and Sections III.D and III.E).*
- *We agree, and our recommendations align with AARP's comment that competitive solicitations can help keep rates affordable.*
- *Under our recommendation to join or create an RTO (or RTO-like regional wholesale power markets without other RTO features), South Carolina would continue to manage its own energy policy. RTO-operated wholesale power markets have integrated renewable energy resources faster than other areas of the country, indicating that they are well suited to accommodate state-level clean energy policies.*

[1] If South Carolina opts to pursue consideration of full PJM membership or partial integration, we recommend to review or participate in the PJM states' ongoing efforts including through the Independent State Agencies Committee (ISAC) and the Organization of PJM States Inc (OMS).

Carolinas Clean Energy Business Association

Hamilton Davis, VP Markets and Regulatory Affairs, Southern Current

- There has been some confusion as to how the savings attributable to SC were calculated given the modeling of Duke's BAA across NC and SC. Some additional clarification on the pro rata allocation of benefits to Duke's SC customers would be helpful.
- Based on the concerns raised during the last Advisory Board meeting pertaining to implications for SC's nuclear fleet from joining PJM, it would be helpful to have additional discussion within the report as to how these facilities could continue to operate even within a wholesale market. Some comments were made regarding the expensive subsidies needed to keep nuclear plants open in states like IL, however, my understanding is that SC would not be adding any costs to its nuclear fleet if those facilities continued to operate in a PJM scenario, rather continuing to operate these facilities may simply forgo lower cost market options that would otherwise be available. Retaining our state's nuclear option may also be highlighted in the context of state-based reliability planning that could continue even within the PJM market.
- State-based planning for reliability also continues to be an issue for certain members of the Advisory Board and the Committee. Additional focus around options like FRR, etc. within PJM should inform future discussions around reliability planning and the menu of options that are available to the state. CCEBA believes that in-state responsibility for reliability will be a critical consideration for the Committee, and thoroughly addressing this issue in the final report will be critical for informing the Committee's decisions on next steps related to market reform.
- Directly addressing the perceived problems with the PJM capacity market and future expectations for meeting reliability of members would be useful.
- In the current regulatory model, there should be a role for both all-source procurement (especially when that procurement is designed to replace or add capacity to a utility system), as well as resource specific procurements (especially when there is an opportunity to procure fixed price energy resources like solar that mitigate fossil fuel volatility or provide customers savings as compared to modeled fossil fuel costs). Additional discussion of this distinction would be helpful.

Brattle Responses and Clarifications: *Edits made in the report. See response to Dominion comment #2 on the nuclear fleet and Dominion comment #29 and Duke comment #9 on PJM capacity market.*

Central Electric Cooperative

Mark Svrcek, COO & Sr. VP of Corporate Strategy, at Central Electric Power Cooperative, Inc.

Executive Summary

1. Wholesale Market Reforms – It would be helpful to clarify that SEEM bilateral transactions are non-firm.

Brattle Responses and Clarifications: *Edited language in the report.*

2. Table ES-1 – Can you explain why the Administrative Costs of a Carolinas JDA would be ½ of similar costs for a Southeast EIM? It would seem that the significantly larger footprint of a SE EIM would require a higher cost burden.

Brattle Responses and Clarifications: *We have updated Table ES-1 to reflect an approximate uncertainty range in costs in alignment with cost ranges experienced in other regions and the below considerations. The allocations to South Carolina for the JDA and EIM cases are similar. The absolute administrative costs of wholesale market operations are most affected by the breadth of functionality and tend to be less affected by the geographic footprint. For example, the U.S. RTOs have broadly similar annual operating budgets and staff sizes despite a 5x difference in peak load between the smallest RTO and the largest. With greater functionality, an EIM would be expected to have a larger absolute budget than a JDA; however, with regional demand that is multiple times larger in a Southeast EIM relative to a Carolinas JDA, the administrative costs per MWh are shared over a larger footprint. The administrative cost estimates in the report reflect the costs experienced in other jurisdictions for these types of market functions, but as indicated in the report, there are few published values for the JDA administrative costs, and so it is difficult to precisely estimate these numbers. We note that the range of alternative participation models that could be pursued may somewhat affect these costs.*

3. Page 5 – at the bottom of page 5, Brattle states "None of these wholesale market reforms would change the state's authority to oversee integrated planning, resource investments, or *retail rates*." (emphasis added) It may be helpful to footnote the limits of state authority over retail rates for Santee Cooper, electric co-ops and municipal electric entities.

Brattle Responses and Clarifications: *Edited language in the report.*

4. Page 7 – Resource Planning and Competitive Investment Reforms – In the opening paragraph, Brattle states "Once the PSC approves a utility's supply plans within the IRP or follow-on processes, the utility develops the resources and, once these resources are completed, becomes eligible to recover associated costs from consumers, including a rate of return on investments."
    a. The CPCN process is not referenced, but it is possible it could be part of the "follow-on processes" that are referenced above. Central recommends a specific reference of that important element of regulatory oversight.
    b. The generic statement of "including a rate of return on investments" does not align with electric co-op rate making principles. Central recommends a footnote acknowledging this fact.

Brattle Responses and Clarifications: *Edited language in the report.*

5. Page 8 – Resource Planning and Competitive Investment Reforms – Transitioning to partial or full reliance on competitive supply investments…
    a. Will the reader understand "…regional resource adequacy mechanism…"
    b. Footnote 11 ignores the Santee Cooper board approval of the project and solely references PSC approval. Since the PSC had no jurisdiction over Santee Cooper board decisions, that clarification should be added.

Brattle Responses and Clarifications: *Edited language in the report.*

6. Table ES-2 – In the "Transition to Partial or Full Competitive Supply Investments" Potential Costs and Risks section, how do market prices ensure reliability?

Brattle Responses and Clarifications: *Market prices alone do not ensure reliability, and nothing in the report should be interpreted to imply this conclusion. As discussed in the report, a precondition for considering reliance on competitive market-based supply investments is that an effective market for attracting such investments when needed to meet the 1-in-10 reliability standard must be in place, ideally one with a demonstrated track record of attracting competitive investment when needed. Furthermore, there are several different competitive resource adequacy constructs that are designed to fulfill a different role depending on the system they operate in.*

For example, PJM is a region that has attracted competitive supply investment sufficient to meet reliability needs in states that do not conduct utility planning, while simultaneously *enabling the PJM states and public power entities that do continue to rely on integrated utility planning to meet their resource adequacy investment needs. On the other hand, SPP and most of MISO (as well as the vertically integrated PJM states), continue to rely on integrated utility planning to meet their resource adequacy investment needs, but use the regional capacity markets for balancing their portfolios.*

MISO's resource adequacy construct is different from PJM's since it is primarily designed to enable capacity balancing for states that rely on utility planning, and it has not been designed to produce prices sufficient to attract competitive investments when needed. The MISO resource adequacy construct and market does produce prices and support trade among these utilities, but should not be relied on (at least in its present form) to attract all future investment needs for resource adequacy without the utilities' integrated planning efforts.

Therefore, resource adequacy constructs and market prices must be fully assessed and vetted while understanding the context (design and intent) of the market-based approach prior to considering reliance on them for meeting future investment needs.

7. Retail Market Reforms

a. On page 14, in the discussion of "partial retail choice," "full retail choice," and "Community Choice Aggregation," there is no reference to the need for well-defined solutions to challenges of provider of last resort obligations, stranded investment recovery, etc. Although more detailed discussion occurs in the body of the report, these challenges should at least be referenced in the Executive Summary section in case the reader only reads the Executive Summary.

b. Regarding "Community Choice Aggregation," a footnote defining "Community" may be helpful.

Brattle Responses and Clarifications: *These challenges are listed in Table ES-4.*

8. Table ES-4 – Partial Retail Choice – Please explain the Potential Benefit of "Would put SC on a more level playing field to attract new businesses to the state"

a. This statement implies that there is evidence that SC is not attracting new businesses to the state at a rate compared to someone (NOTE: there is no comparison stated in the potential benefit)

b. The listed benefit seems arbitrary and ill-supported. Central recommends striking this item unless it can be supported.

Brattle Responses and Clarifications: *Edited language in the report.*

Background Section

9. B. Overview of South Carolina's Electricity Sector

   a. The opening paragraph mentions nothing about the electric co-ops or municipalities. According to SC State Energy Office statistics, roughly 1/3 of SC's customers and electric energy consumption are related to electric co-ops. To not acknowledge this material piece of the State's electric makeup is not appropriate.
   b. In the opening sentence of the second paragraph, Brattle states "To provide electricity service, South Carolina ***utilities*** (emphasis added) are granted monopoly status in their service territory ***and*** (emphasis added) are regulated by the South Carolina Public Service Commission…"
      i. Only IOUs are rate-regulated by the PSC.
   c. Figure 1 states that a utility "Builds and owns all resources"
      i. "All" is not correct
   d. Page 23 – The paragraph directly below Figure 1 includes Santee Cooper in the IOU sentence. That should be corrected.

Brattle Responses and Clarifications: *Edited language in the report.*

Wholesale Market Reforms

10. Overview – On the top of page 32, "Under each of these wholesale market reforms, the state retains the authority to set the process to oversee and approve resource investments and retirements, generation and transmission siting, and retail rates."

11. Status Quo

   a. Opening Sentence - "The *major* (emphasis added) utilities in South Carolina serve customer load in their service areas with their own generation."
      i. Co-ops in aggregate are similar in size of to IOUs. Central takes exception to the term "major."
   b. Page 35 – In the paragraph that begins "In the minutes-to-minute…" – drop the "s"; Brattle also refers to "VACAR-South" in this paragraph. VA dropped out so replace with new Carolinas entity.

Brattle Responses and Clarifications: *Edited language in the report. The reserve sharing group continues to be called VACAR-South Reserve Sharing Group (VRSG).*

Enhanced Regional Transmission Planning

12. See attached email from Chris Ware (VP-Engineering at Central). Corrections need to be made to draft report to accurately state the current transmission planning landscape in SC.

a. [Email from Chris Ware] I gave feedback on one section to Mark concerning transmission planning on page 68. Mark indicated he was attending. I will be at the G20 meeting this morning at ECSC.

b. The report stated “South Carolina utilities participate in the FERC-regulated South Carolina Regional Transmission Planning group (Duke also participates in Southeastern Regional Transmission Planning).” This statement is NOT true. Duke does NOT participate in the SCRTP but does participate in the SERTP. The last two meeting notes from the SCRTP are attached. (from https://www.scrtp.com/meeting-archives.html) Duke does not participate in the SCRTP based on the meeting notes.

c. Likewise, DESC and Santee Cooper are not members of the SERTP. SERTP members are on the SERTP website (http://www.southeasternrtp.com/). “The SERTP has expanded several times, both in the scope and in the size of the region, since its initial voluntary formation and now includes the following Sponsors: Southern Company (SCS), Dalton Utilities, Georgia Transmission Corporation (GTC), the Municipal Electric Authority of Georgia (MEAG), PowerSouth, Louisville Gas & Electric Company and Kentucky Utilities Company (LG&E/KU), Associated Electric Cooperative Inc. (AECI), the Tennessee Valley Authority (TVA), and Duke Energy (Duke Energy Carolinas, LLC and Duke Energy Progress, LLC). As a result of this expanded size and scope, the SERTP region has become one of the largest regional transmission planning processes in the United States.”

d. Note that DESC and Santee Cooper are not in the list of sponsors for the SERTP.

e. Essentially, DESC and Santee Cooper plan together in the SCRTP. The rest of the Southeast plans together in the much larger SERTP. Having said that, the entities are required to exchange information, but I would not say that the planning organizations fundamentally plan as one as the report suggests.

Brattle Responses and Clarifications: *Edited language in the report.*

Resource Planning and Competitive Investment Reforms

13. Status Quo with Utility Integrated Resource Planning

a. Page 91 – “Through these IRP processes, utilities propose and the PSC approves generation investment (and retirement) decisions.”
    i. Central doesn’t believe this statement is accurate. The PSC approves/rejects a plan in the IRP process. Generation investment decisions are approved in the CPCN process.

Brattle Responses and Clarifications: *Edited language in the report.*

Statewide Resource Planning Across All Utilities in South Carolina

14. Page 96 – In discussing “Potential Advantages,” Brattle states – “Reduced reliance on utility judgement to make policy decisions and accurately forecast the future (though this benefit is achieved only by increasing reliance on a state agency’s judgement over the same uncertainties).”
    i. Is it Brattle’s assertion that a “state agency” has better judgement than a “utility” in forecasting load and generation planning? If so, Central disagrees with this assertion.
15. Page 96 – “…then state-overseen IRP can fill the role of assessing and planning for policy goals that will not otherwise be addressed by a purely market-based construct…”
    a. The phrase highlighted may conflict with current statutory IRP requirements for a utility. I’m no lawyer but wanted to highlight the possibility.

Brattle Responses and Clarifications: *Edited language in the report.*

Retail Market Reforms

Overview of Potential Retail Market Reforms

16. Page 120 – Central questions the use of “better” in phrases in the 2nd paragraph – “…negotiate *better* (emphasis added) rates…would allow customers to *better* (emphasis added) pursue their own preferences…

Status Quo with Exclusive Utility Service for Retail Supply

Description of Status Quo in South Carolina

17. Page 122 – The opening paragraph includes “…and the PSC approves distribution system capital investments on operation plans, and sets the retail rates utilities use to recover these investment and operating costs.”

a. These statements ignore co-op governance and Santee Cooper board authority to regulate these items. *NOTE*: Both co-ops and Santee Cooper are subject to CPCN requirements for generation and transmission projects.
b. Similarly on page 123, there are references to PSC, ORS, on state oversight on retail rates without reference to those utilities that have board governance over retail rates.

Brattle Responses and Clarifications: *For comments 16-17: edited language in the report.*

Partial or Full Retail Choice

Description and Relevant Case Studies

18. Page 128 (2nd paragraph) – "Standard offer service rates are developed under commission oversight…"

Same observation as above.

Brattle Responses and Clarifications: *Edited language in the report.*

Coastal Conservation League

Eddy Moore, Energy Program Director, Costal Conservation League

Market Reforms for South Carolina's Electricity Sector, issued by The Brattle Group on February 21, 2023. These comments focus on three areas of the report.

I. Recommendations regarding wholesale market reform options.

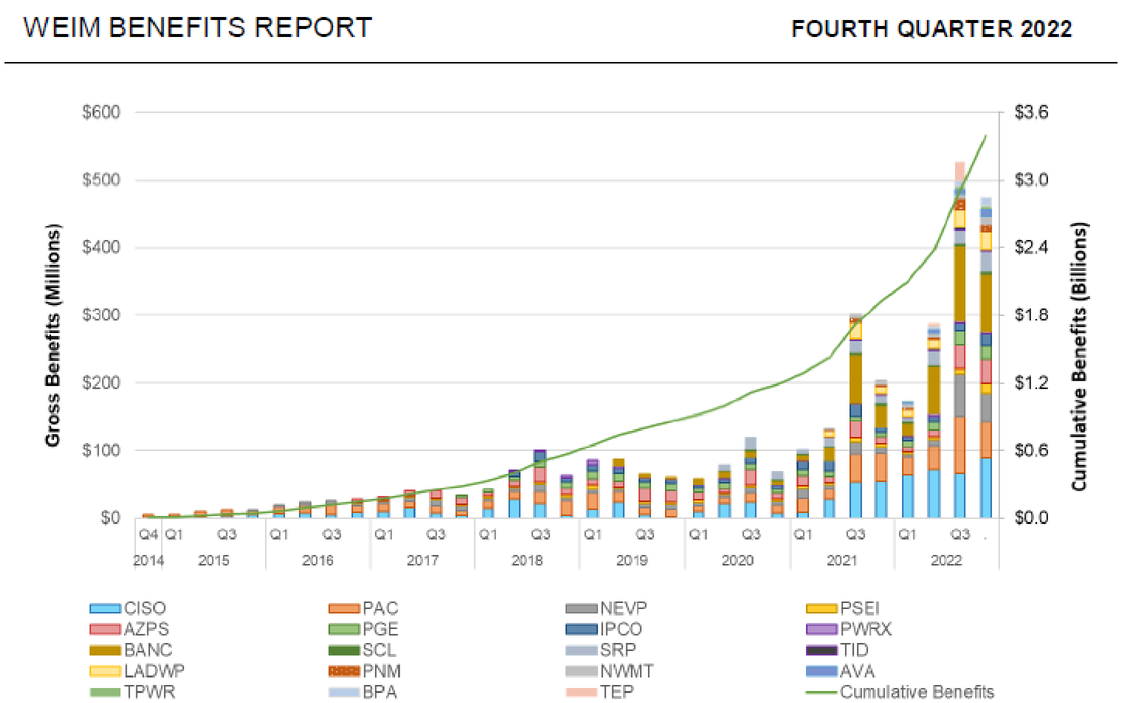
We agree with Brattle's recommendation that joining PJM would yield major cost savings for South Carolina ratepayers, and would yield the greatest benefit of any of the wholesale reform measures that were studied. This is the first of four wholesale market reform recommendations that Brattle presents on page 7.

Regarding cost benefits, Brattle estimates that joining PJM would save $362 million in the single year 2030, with continuing, growing annual benefits thereafter. More generally, the benefits of joining PJM would include increased system reliability, lower energy/capacity costs, enhanced resource deployment, elimination of wheeling rates within the PJM region inclusive of North

Carolina, and a robust transmission planning process. Critically South Carolina would retain its regulatory authority over its utilities and would benefit from access to a large market.

A second option--formation of a Southeast RTO on the footprint of the current Southeast Energy Exchange Market ("SEEM"), would save South Carolina ratepayers approximately $183 million per year and provide comparable other benefits in terms of reliability and planning. Creation of an entirely new RTO, however, would be much more time and resource intensive than joining the existing PJM RTO because it would require coordination with other states and their utilities to organize, staff the organization, develop rules, receive regulatory approvals, and commence operations.

The third alternative recommended for South Carolina is creation of an Energy Imbalance Market (EIM) in conjunction with a regional resource adequacy program. Both would overlay the electrical and geographic footprint of the voluntary SEEM market. The estimated benefit of an EIM appears to be modest compared to the cost savings currently being delivered by the Western Energy Imbalance Market (WEIM). In the chart below cumulative savings from the WEIM are shown on a quarterly basis from market commencement in 2014 through November 2022. Over that time WEIM has returned $3.4B in in total savings to the states the market serves. The scope of savings has increased over time with returns tracking $400M a quarter.



GRAPH 1: Cumulative economic benefits for each quarter by BAA

Because real world experience suggests that EIM benefits could be significantly larger than those estimated in the Draft Report we request further analysis and refinement as to an EIM's potential for the Southeast. As shown below in Table 13 from the report, when costs are backed out of the EIM and the proposed Joint Dispatch Agreement between the Carolinas, the remaining cost benefits are low.

TABLE 13: ESTIMATED 2030 BENEFIT AND COSTS OF WHOLESALE MARKET REFORMS FOR SOUTH CAROLINA (IN 2022$ MILLIONS/YEAR, RELATIVE TO STATUS QUO)

	Operational Savings [A]	Investment Cost Savings [B]	Administrative Costs [C]	Annual Net Benefit [D]
Carolinas JDA	$10–$13	N/A[108]	$9	$1–$4
Southeast EIM	$22–$27	N/A[108]	$18	$4–$9
Southeast RTO	$87–$106	$94–$117	$40	$140–$183
Join PJM RTO	$163–$200	$158–$198	$36	$285–$362

Notes:

[A] and [B]: Values are from Section II.G. The real-time market benefits, which represent all of the JDA and EIM benefits, will be understated because the market simulations do not fully capture real-time challenges, such as intra-hour load following.

[C]: Values are from Sections II.C, II.D, and II.E for JDA, EIM, and the two RTO reform scenarios, respectively.

[D]: [A] + [B] − [C].

This result can be explained by the optimization that occurs in both day-ahead and real time markets operated by RTOs. In the footnote to the table the JDA and EIM market simulations are noted as "understated" as a consequence of not capturing inter and intra hour dispatch and load following efficiencies. In real-time RTOs and EIMs dispatch at either 5-minute or 15-minute intervals in order to capture swings in electrical demand the occurs throughout the operating day. Market operators in turn have the systems to settle purchases and sales on a 5-minute basis to accurately account for generation commitments, decommitments, sudden ramps in demand, etc.

To the extent that inter-hour efficiencies are not captured in the Report's modeling the margin of benefits should be greater not only for the JDA and EIM but also for the RTOs. In the final report to the South Carolina Legislature, we ask whether sensitivities can be run and added to the Report which would better reflect inter and intra hour activity in the market reform cases.

Brattle Responses and Clarifications: *We agree with CCL that several of the modeling assumptions used in the study imply that our estimates of operational savings are conservatively low. As pointed out by CCL, the results reflect only hourly granularity with full foresight of real-time market conditions. This will understate the intra-hour, real-time benefits of a JDA, EIM, and RTO and result in understated total net benefits, particularly relative to the*

Status Quo. As discussed with the Study Committee in previous meetings, we have intentionally endeavored to make sure our estimate of net benefits is conservatively low and have added text to the report outlining the conservative nature of our estimates.

II. Natural Gas Price Volatility

Natural gas prices on both a spot and forward basis have experienced volatile price swings over the past 12-months at levels not experienced in the recent past. This volatility can be attributed to several factors including changed market fundamentals, seasonal demand, and structural changes including LNG production for export markets. During storm Elliott natural gas prices moved to extreme scarcity conditions as pipeline compressor stations failed throughout the region. Because Natural Gas price volatility has such a profound impact on the benefits of wholesale electric market reform in the Southeast we ask that Brattle either include a high price scenario quantitatively, or qualitatively explain how gas prices have been consistently volatile over the past 20 years, and incorporating that volatility will significantly raise EIM benefit estimates.

Brattle Responses and Clarifications: *As stated above, the modeling assumptions imply that our estimates of operational savings are conservatively low. See discussion and clarifications now incorporated in the report and Appendix C.*

III. Securitization of the remaining book value of retiring coal generation.

At page 119, the Draft Report recommends that the General Assembly “confirm or clarify regulatory policies related to the retirement of uneconomic aging resources.” Within that recommendation, Brattle recommends that the General Assembly “authorize the PSC to consider” various cost recovery mechanisms, including securitization. Because securitization of retiring assets is not authorized under current South Carolina law, the first sentence of this recommendation should be clarified to read “Authorize securitization and clarify regulatory policies . . .” Authorizing securitization is essential in order to have this option on the table, and it thus is not merely a confirmation or clarification of current law.

Brattle Responses and Clarifications: *Edited language in the report.*

Additional Questions submitted on 3/13/23 *(Brattle responses in italics)*

1. It seems that the EIM shows small benefits because the modeling suggests SEEM is already providing a lot of those benefits, per the chart showing market transactions only increase marginally going from SEEM to EIM on page 79. Also, pages C-6 and C-7 assume participants efficiently use SEEM to optimize and offer in spare transmission. Were the modeled SEEM transactions benchmarked (for MWh quantity and $/MWh value to estimate total $ savings) against actual SEEM transactions to date, to ensure the model is not overstating the extent to which participants actually use SEEM to optimize?

Brattle Responses and Clarifications: *The simulated SEEM transactions in our 2030 Status Quo Case are more than ten times higher than the observed historical transactions in SEEM since its launch (comparing the current SEEM footprint, excluding Florida utilities, with the same footprint in the model). Therefore, our representation of the SEEM in 2030 is significantly more efficient than SEEM has been since its launch. This indicates that the estimated benefits of the other market reform options studied, the JDA, EIM, and RTO options, are conservatively low (See Appendix C).*

2. Per page C-4, what "enhancements" were used to produce sub-hourly market transactions to overcome the hourly PSO granularity due to limited data availability? Did those enhancements capture the differences between SEEM and EIM?

Brattle Responses and Clarifications: *We did not model sub-hourly granularity. See response to CCL Comments Part I.*

Also, the consideration of potentially higher fossil generation led me to several questions please as I look at the Appendix on modeling:

3. The Dominion's 2021, 2022, and 2023 IRPs are significantly different. Which Dominion IPR is the basis of the 2030 projection?
    a. I.e., I believe the earlier 2021 IRP had a new 1000+ MW CC and two coal retirements (Wateree, Williams).
    b. The 2022 had new CTs, but no new CC in the 2020's. Can't remember whether it was one coal retirement in 2028 or two.

c. The 2023 IRP has a new joint CC with Santee Cooper; Wateree retires in 2028 but Williams doesn't retire until 2030. So does the modeling retire Wateree and Williams, or just Wateree?

Overall, it seems to me that Stakeholders need to know what resources are added and retired in the modeling across all utilities serving SC.

Brattle Responses and Clarifications: *We used the information provided by utilities on their latest resource plans available at the time we were building the model. See Appendix C.*

4. The shift to more in-state gas and coal generation in the 2030 scenario is expressed in MWh. This does not say anything about heat rate, but one would expect the whole PJM footprint to slightly move towards more efficient heat rate (so that more MWh is not necessarily more fuel). Can you say anything about the gas heat rates?

Brattle Responses and Clarifications: *Yes, the more efficient units increase production and displace less efficient units. As a result, fuel usage and emissions decrease across PJM and the Carolinas in the PJM RTO Case.*

5. Is the increased generation basically driven by the shift from local winter peaking systems to a PJM-wide summer peaking system (i.e., solar in NC/SC has already tended to back down summer generation, but it would run again if we were tied to PJM?).

Brattle Responses and Clarifications: *The increased generation in the Carolinas, under the PJM RTO Case, is due to efficient thermal resources in Duke displacing less efficient resources in the PJM footprint. If additional solar resources came online in the Carolinas, it would likely free up additional efficient thermal and increase the benefits of market participation for South Carolina customers.*

6. Page C-21: SCE&G OATT rates seem dramatically higher than Duke and Santee Cooper. How does this affect, for instance, imports to Santee Cooper? My impression is that Santee Cooper imports from Southern are wheeled through SCE&G/Dominion. Does the model, for instance, prefer imports from Duke instead of Dominion and Southern due to the higher Dominion tariff? Is this a significant effect?

Brattle Responses and Clarifications: *The model accounts for the contract paths provided by the utilities. Santee Cooper is able to purchase from Southern, at the Southern OATT rate, based on the import limit provided by Santee Cooper.*

Dominion Energy South Carolina

Lee Xanthakos, Director Electric Transmission, Dominion Energy South Carolina

1. Given the report's conclusion that the SC utilities can just buy their power needs from the PJM market, how likely is it for any of the SC utilities to build future gas-powered generation in the state of SC.

Brattle Responses and Clarifications: *The report does not reach the conclusion that SC utilities "can just buy their power needs from the PJM market." The report's recommendation is for the legislature to pursue membership, creation, or integration with an RTO, while maintaining the vertically integrated utility model in the state at this time. Under that recommendation, the South Carolina PSC would continue to regulate and approve, through the IRP process, which generation resources are built by investor-owned utilities in the state or through competitive all-source procurements.*

2. We know that nuclear plants in the Northeast have struggled to stay online and made have retired. Please explain the risks posed to nuclear plants if the Carolinas joined and RTO.

Brattle Responses and Clarifications: *As addressed live at the March 14th, 2023 Advisory Board meeting, nuclear plants in much of the Northeast, Ohio, and Illinois operate as merchant facilities, due to previous generation divestiture of those resources in those states. As noted in the report, we do not recommend generation divestiture in South Carolina at this time. We have further cautioned that nuclear resources in particular should not be considered for divestiture, even if the state were to pursue more extensive restructuring in the future. The full cost recovery through state-regulated rates that exists for nuclear plants in South Carolina today would continue to exist unchanged under the recommendations made in the report. Under the recommendations made in the report, customers in South Carolina would continue to pay for the existing nuclear facilities in the same way they do today, at rates approved by the South Carolina PSC. Furthermore, the owners of the nuclear plants in South Carolina would continue to have the option to operate their plants in the same way they do today (as self-scheduled* *resources in an RTO), without affecting the way that costs for these facilities are recovered from customers.*

3. I have been on PJM stakeholder calls, and I was very confused as to how anything is accomplished with so many companies viewing and arguing issues from their own perspectives. On a scale of one to ten, how functional would you rate the existing stakeholder process in PJM to be? How likely is it for SC companies to have an impact on such a group?

Brattle Responses and Clarifications: *We have communicated to the Study Committee in previous meetings that being a member of a multi-state RTO does require reaching consensus on the RTO rules with other members, consistent with the unique governance processes within each RTO region (see detailed discussion of these differences and relative merits of alternative governance structures in the report).*

If South Carolina wished to start fresh under a new governance structure, one option discussed in the report would be to pursue a new RTO with state agencies and companies in South Carolina acting as founding members of that RTO. We recommend that the South Carolina legislature weigh (or direct the PSC to weigh) the benefit of being a founding member in a new RTO against the larger monetary benefits of fully (or partially) joining PJM before deciding which pathway to pursue. As discussed in the report, the partial PJM participation option would require PJM to create such an option (similar to the Markets+ option that SPP offers in the Western U.S.) and make it available to the South Carolina utilities.

4. The first sixty-seven pages of the report are not specific to SC. They report on general pro/cons of various market structures, but they have very heavy bias towards the benefits of an RTO. How early in this process did Brattle determine that the RTO structure was superior to EIM, JDA, and the existing structure? It seems there were some predetermined preferences before the study even began.

Brattle Responses and Clarifications: *The recommendation to join an RTO is based on the results of our analysis. As discussed in our initial meeting with the Study Committee in September 2021, the large majority of all studies (ours and others') regarding the potential benefits of joining or creating RTOs identify net benefits. However, there are exceptions and unique circumstances where an individual utility's customers may not benefit (for example, we* *have previously analyzed membership in an RTO for utilities in other parts of the country and found that there were no net benefits for those customers). In the case of South Carolina, there are large net benefits for customers in joining an RTO; this finding is the basis for our recommendation.*

5. Isn't there a freeze on new solar/wind assets in PJM?

Brattle Responses and Clarifications: *There is not a freeze on new solar/wind assets in PJM (i.e., generation projects proceeding through the queue and coming online). There is however a temporary delay on new wind and solar generation resources being allowed to enter the interconnection queue while PJM seeks to permanently speed up its interconnection processes and clear the large backlog of existing wind and solar projects already in the queue.*

According to PJM Queue data, as of April 21, 2023, over 4 GW of projects processed in the last half of 2022 were issued Interconnection Service Agreements, the final step in the PJM interconnection process before a project starts operations.[2] *In efforts to clear a backlog of approximately 300 GW of remaining projects in the interconnection Queue, PJM is currently transitioning to a more rapid interconnection process that was approved by FERC in 2022. As part of that transition, PJM issued a pause on new wind and solar interconnection requests until at least 2025.*

6. If so, aren't new assets more likely to get built in SC especially now that SC company queues have transitioned to a cluster study process?

Brattle Responses and Clarifications: *The PJM interconnection Queue is expected to begin processing new interconnection applications on a more expedited cluster study basis starting in 2025, which is the earliest that South Carolina utilities could join the RTO.*

PJM's generation interconnection queue process would not apply to South Carolina utilities under a partial PJM participation option (similar to the Markets+ option SPP is providing in the Western U.S.), should PJM make such an option available.

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[2] https://www.pjm.com/-/media/planning/services-requests/interconnection-study-statistics.ashx; https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

7. In the PJM interconnection process, how long does it take for a generator developer to go from the Application to a completed Facility Study?

See response to DESC comments #5 and #6 above.

8. Does PJM currently have enough generation capacity to meet its existing needs plus the additional burden the SC companies (each with their own retirement plans) will put on it.

Brattle Responses and Clarifications: *Yes. PJM's expected reserve margin for Summer 2023 is 29.5% and capacity margins have historically reached around 28% of peak loads in PJM.*[3] *Additionally, the South Carolina companies have planned and built resources to satisfy their own resource needs (including reserve margins) and they will bring those resources into PJM if South Carolina chooses to join PJM.*

9. In an early presentation, Brattle showed that being or not being in an RTO does not play a role in retail rates. In this report, the RTO option results in +/- $300 million benefits, but how would that translate into retail rates?

Brattle Responses and Clarifications: *The net benefits reported in the study indicate the reduced cost of serving load for the utilities in South Carolina from each of the market reform option analyzed. Under the recommendations in the report, the retail ratemaking process for investor-owned utilities in front of the South Carolina PSC will remain as it does today, and utilities will need to reflect the lower cost of serving load (e.g., through lower fuel costs, operating costs, investments, etc.) in their future rate cases. Therefore, how cost savings are apportioned to customers would depend on the current retail ratemaking process approved by the PSC, but would typically be returned to customers in consideration of cost-causation, efficiency, and other ratemaking principles.*

10. For DESC, reserves are primarily carried on Saluda Hydro which is a recreational lake. The primary drivers for generation at Saluda Hydro are environmental in nature. DESC does not generate from Saluda Hydro except for short instances following the immediate trip of a resource and then gets off it as soon as possible. Since Saluda Hydro does not run now, and

[3] See https://www.pjm.com/-/media/planning/res-adeq/20230106-forecasted-reserve-margin-graph.ashx and https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx, pg. 16.

would not run in the future (due to the environmental constrains) how would DESC safe on fuel costs that would result from a lower reserve margin? It seems the study does not consider the real-life ways we operate our system.

Brattle Responses and Clarifications: *Participation in an RTO market reduces the operating reserves needed in the footprint and ensures that the lowest-cost resources are selected to provide reserves. If Saluda is among the lowest cost options to hold reserves in the market, it will be selected to provide that service and DESC would be compensated for providing the service. Neighboring utilities in the RTO (e.g., Santee Cooper or Duke) may save on fuel costs by not having to hold reserves on one of their resources.*

11. Explain how lowered reserve margins help increase reliability?

Brattle Responses and Clarifications: *The larger footprint realized by membership in an RTO would allow South Carolina utilities to achieve the same reliability standard with a lower planning reserve margin or, as a corollary, a higher reliability standard for the same planning reserve margin. This fact is reflected in reliability studies. According to the DESC 2023 Planning Reserve Margin Study, a 20.1% winter reserve margin is required in DESC in 2026 in order to reach the industry-standard reliability metric of a 1-in-10 loss of load expectation (LOLE),*[4] *whereas PJM analysis shows a 14.7% reserve margin is required to reach the same reliability for the 2026/27 delivery year.*[5] *To illustrate, if PJM had an installed reserve margin of 18%, it would have a higher reliability metric than DESC would if its winter reserve margin were 20.1%.*[6] *Chairman Thomas of the Arkansas PSC provided the Study Committee with a more extensive explanation of the benefits customers in his state have experienced due to this fact. See his comments to the Study Committee on September 1, 2022.*

12. Your report says that for $2 million a company can join PJM. In 2002 SCE&G spent 30-40 million to join GridSouth. The $2 million estimate seems extremely low. The complexity of integration into an RTO seems understated.

4 https://dms.psc.sc.gov/Attachments/Matter/7c68375d-9744-4d5f-b571-1c98ff07266e

5 https://www.pjm.com/-/media/planning/res-adeq/2022-pjm-reserve-requirement-study.ashx

6 PJM's actual installed reserve margin for the most recent forward capacity commitment of 2024/25 was 20.4%. See https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx

Brattle Responses and Clarifications: *We have updated the utility-side RTO integration costs with cost estimates based on public information. These range from $1 million to $37 million in one-time utility-side integration costs. See the "RTO Implementation Considerations For South Carolina" in Section II.E and report footnote 75.*

13. Page 35 – says SEEM is limited to its members. This is not accurate. Any generator or load within the SEEM footprint can participate including IPPs or others.

Brattle Responses and Clarifications: *Edited text in response to this comment.*

14. Page 36 – it is not fair to draw conclusion on SEEM since it has only been in effect for 3 months. Also, SEEM is an energy market. There were many trades scheduled on an hourly basis during the period, but there were no SEEM trades on 12/24 because everyone was starving for power for their own extremely high demand. Suggesting that SEEM did not work correctly on 12/24 is disingenuous.

Brattle Responses and Clarifications: *Edited text in response to this comment.*

15. Page 37 – Is interesting that Brattle could only identify 2 pros to the status quo. I thought there might be more.

16. Page 38 – the report says that for the Status Quo "Administrative costs may exceed the operational savings." Nothing could be further from the truth because we have operated under this system for decades and we know and manage the administrative costs. On the other hand, the SC companies have not experience with the risks of an RTO, so I would say that scenario is more likely to result in higher and unexpected administrative costs.

Brattle Responses and Clarifications: *Edited text in response to this comment.*

17. Page 38 – 3rd, 4th, and 5th bullets are virtually the same bullet. Also, there no justification to saying that lowering reserve margins would increase reliability.

Brattle Responses and Clarifications: *See response to Dominion comment #11.*

18. Page 44 – All the utilities in SC already run a security constrained dispatch, and the existing system already has sufficient situational awareness which can be demonstrated by the fact that the Southeast has had no uncontrolled cascading outages like California, the mid-West, and the Northeast. There is no evidence that there would be fewer emergencies as the report states, nor that they would be identified faster. All the assumptions in this section assume the Southeast functions as poorly as the West did before they made their changes, and that is not the case. Just because an EIM potentially benefited the West's reliability as described here, there is no evidence or study that suggests the same for SC.

Brattle Responses and Clarifications: *The description referenced in this comment is a qualitative assessment of some of the reliability advantages of pooling the resources of many utilities across a larger geographic footprint, based on a report written by FERC staff. While such pooling is made more effective with a SCED, the underlying driver of the reliability benefits is the larger geographic visibility and resource pool, which provides more options to the system operator in the event of an emergency (especially a resource adequacy emergency, such as that experienced during Winter Storm Elliott). The experience in the Western U.S. is informative as lawmakers in South Carolina consider market reform options. However, these are not assumptions used in Brattle's analysis of the net benefits for an EIM in the Southeast, and our analysis does not make any assumptions about the relative efficiency of Status Quo operations in the Southeast versus the West.*

19. Page 71 – states reliability would be improved. DESC's SAIDI is 78 minutes. This is far lower than most utilities, and it is mostly due to tree trimming programs and SCADA switches. Even Brattles own early presentation from its early presentation to the study committee stated that being in an RTO does not improve reliability. Please remove this because it is not accurate. Reliability if almost all Distribution system related.

Brattle Responses and Clarifications: *Edited report to clarify. This comment misstates Brattle's presentation to the Study Committee in the March 23, 2022 meeting. It is correct, that the vast majority (~95%) of reliability events are at the distribution system level, which would not change for the better or worse by joining an RTO. However, reliability on the Bulk Power System, although responsible for a small portion of outages, would be improved due to regional cooperation under an RTO. Additionally, see comments of Chairman Thomas of the Arkansas PSC to the Study Committee on September 1, 2022.*

20. Page 72 – there is no evidence to support that RTOs have greater resiliency during a low probability event. Blackouts in Texas and California point to the opposite as does winter storm Elliott when PJM cut FIRM sales to Duke causing them roll black outs.

Brattle Responses and Clarifications: *Recent experience during Winter Storm Elliot in December 2022 in PJM and MISO is an example of how RTOs have greater resiliency during low probability events.*[7] *Faced with high outage rates from coal and gas-fired generation that also affected large portions of the South, Northeast, and Midwest, no customers in PJM or MISO experienced load shedding during the event, unlike customers in neighboring regions without an RTO. PJM and MISO were net exporters of power on December 23rd 2022, supporting neighboring regions leading up to the peak load of the Winter Storm Elliot event. MISO was able to continue to export power at similar levels to neighboring regions (most notably to TVA, which was severely stressed and ultimately had to shed load despite the support from MISO) throughout December 24th. PJM was also a net exporter throughout the majority of the event, but was forced to curtail exports to lower levels during the peak on December 24th than it had been providing previously, due to the high rate of forced outages from gas-fired generation, in order to ensure no load shedding would occur within its footprint.*

As stated in previous Study Committee and Advisory Board Meetings, the market structures in California and Texas are not consistent with our recommendations. In the case of Texas, its experience with very limited transmission interconnection with neighboring regions would not be applicable since South Carolina is interconnected to the Eastern Interconnection; further, Texas policymakers chose to accept a lower level of resource adequacy compared to all other regions of the country (both inside and outside RTOs).

21. Page 74 – please remove reference to Dominion Energy Virginia. For one, it is out of place in an RTO table.

Brattle Responses and Clarifications: *Edited table to clarify. Dominion Energy Virginia is a member of PJM, which is an existing RTO. The benefits listed in Table 9 for Dominion Energy Virginia were calculated by Dominion and filed with state regulators in Virginia and North Carolina. They illustrate the experience of other states in the region, which is relevant information for South Carolina lawmakers.*

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7 See https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx and https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf.

22. Page 85 – the first paragraph describes the benefits to PJM if the Carolinas were to join. The report implies the saving of $63 million is for the Carolinas, but that is all PJM benefit, so it does nothing for DESC customers.

Brattle Responses and Clarifications: *The benefits identified are for South Carolina customers. Edits made in the report to clarify.*

23. Page 86 - These JDA & EIM cost are overstated. We know that because SEEM, which is very similar is far less.

Brattle Responses and Clarifications: *We have updated Table ES-1 to reflect an approximate uncertainty range in costs in alignment with cost ranges experienced in other regions. The allocations to South Carolina for the JDA and EIM cases are similar. The Brattle team has endeavored to be conservative in our estimate of net benefits for all market reform options studied. The administrative costs for the JDA and EIM options are based on costs experienced elsewhere as explained in Sections II.C and II.D respectively. If the realized administrative costs for a JDA or EIM turn out to be lower for South Carolina than assumed in the report, net benefits for South Carolina customers would be higher than estimated.*

24. Page 104 – The middle paragraph understates the criticism of PJM. Several large PJM companies have opted out of the capacity market. In fact, given its conservative nature, it is more likely that DESC would opt for a fixed resource requirement as DEV has done. Therefore, the assumed benefits of joining an RTO would only be transmission related, but they are also offset by SC customers paying for transmission upgrades in other parts of the country.

Brattle Responses and Clarifications: *The operational and investment benefits estimated for South Carolina customers due to the Carolinas joining PJM as shown in Table ES-1, would be achieved even if South Carolina utilities opted for PJM's "fixed resource requirement" (i.e., effectively opting out of the capacity market). See response to Duke comment #32 for additional detail.*

25. We discussed the capacity in the PJM queue (it was very large) but we all know that a small fraction of the generators in the queue will move to fruition. To give an accurate reflection of that, I think some estimate should be provided. Also if the majority of those generators are DERs, they do nothing to help the Carolina's that peak in the winter. Discussion should be given on that as well.

Brattle Responses and Clarifications: *See response to Dominion comments #6 and #7 above.*

26. Most of the audience does not recognize the difference between the planning numbers used in the study and how different they can be from actual daily operational values. More emphasis explanation should be given on this. Otherwise, the readers could inadvertently overestimate transfers that what could actually happen in reality.

Brattle Responses and Clarifications: *The analyses conducted in the report take into account plant-level operational restrictions provided by the BAAs in South Carolina. Therefore, bilateral and market transfers shown in the report reflect those operational constraints.*

27. I think the report need to very clearly and loudly clarify that it has not considered the transmission that could be needed. Building large transmission project is extremely difficult costly, and we (that is DESC) know the transmission is not there. Ignoring the importance of this gives a very false impression the possibilities.

Brattle Responses and Clarifications: *Our analysis assumes that only the existing transmission assets, or planned assets expected to be online by 2030, are available. Therefore, the net benefits reported are what is feasible given that transmission infrastructure. If South Carolina utilities build new transmission infrastructure that increases the ability to trade across the market footprint, with the approval of the South Carolina PSC, the benefits of joining a regional market would increase. In this way, our estimated benefits are conservatively low.*

28. It is also not clear if expansion costs in PJM would hurt/help customers in SC. The report needs to explain that SC customer would be paying for upgrades in the SC region as well as other regions, and we do not know what those costs are. I doubt members of the committee understand this detail.

Brattle Responses and Clarifications: *Edited text in the report to clarify.*

Duke Energy

Tigerron A. Wells, Director State Government Affairs, Duke Energy

Draft Comments

Please see below Duke Energy's factual questions for the Brattle Market Reform Confidential draft report submitted on Monday (03/13/23).

1. Capacity Cost: Please explain the basis for valuing capacity at a gross cost of new entry (CONE - $308/MW-day) in developing the capacity benefit for Duke Energy and South Carolina rather than using PJMS's most recent capacity clearing prices (2022/2023 BRA: $50/MW-day; 2023/2024 BRA: $34/MW-day); how would this change/affect the quantified benefit and what sensitivities did Brattle perform?

Brattle Responses and Clarifications: *The investment savings costs from joining an RTO are due to investments in new generation resources that can be deferred by having a lower effective planning reserve margin in the RTO (due to greater peak load diversity in the larger footprint). Gross CONE is representative of the investment needed to build new generation resources.*

2. Over-Generation: The Brattle report arrives at production benefit by generating as much as 16 percent higher than expected for Duke Energy and selling into the market; please describe what incremental cost the model applied given higher starts, more maintenance and exposure to production penalties with likely higher forced outage; please also provide capacity factors for Duke Energy units as modeled in 2030 for all cases.

Brattle Responses and Clarifications: *As discussed live on the March 14th Advisory Board Meeting, we model the entire Duke balancing area obligations, including municipal and co-op utility loads across North and South Carolina that are located within the Duke BAA, but not served by Duke. We confirmed the representation of load in the Duke BAA in written exchanges with Duke in addition to cross-referencing load data to public sources such as the EIA.*

3. Fuel Availability: The Brattle report appears to assume unlimited fuel availability, both coal and natural gas to support over-generation. Please describe what additional costs or constraints to availability were included in the model to factor in known fuel security challenges.

Brattle Responses and Clarifications: *As addressed live at the March 14, 2023 Advisory Board meeting, we modeled fuel supply limits using the data provided by utilities as a constraint in our simulation.*

4. Emissions: Please describe how Brattle's analysis factored emissions into the model and report, and whether there should have been some appropriate limit to over-generation from current levels.

Brattle Responses and Clarifications: *See response above to Duke comment #2. The model includes emissions rates and related costs for all emitting units as provided by the utilities. We model the Cross-State Air Pollution Rule (CSAPR) for SO_2 and NO_x emissions, with allowance prices taken from S&P Global.*

5. Savings Basis: Can Brattle confirm the primary basis for representing production cost benefit results from selling Duke Energy's and SC providers' energy into PJM at an average market clearing price of approximately $30/MWH from a Duke Energy average system cost of approximately $15/MWH?

Brattle Responses and Clarifications: *In the case where South Carolina joins PJM, we calculate revenues earned by selling into the PJM market using the Locational Marginal Prices (LMPs) at each generator location. This is consistent with how market sales are compensated in an RTO. Average system cost is not used in this calculation.*

6. System Costs: In its last Advisory Committee meeting (12/19), Brattle was unable to resolve system cost errors where modeled costs were as much as $10 above expected average cost of approximately $19, or over 50% overstated. Duke Energy provided supplemental data that appears not to have been used. Please describe how Brattle was able to correct the pricing error in its final modeling? Alternatively, provide an estimate the impact of the error

on production cost benefits the study produces. If modeled prices are higher than observed prices, how would this impact production benefit results.

Brattle Responses and Clarifications: *We used all data provided by Duke in the model. Since the 12/19 meeting, we have updated several features of the Status Quo model, including implementing gas price data provided by Duke and Santee Cooper, updating OATT rates provided by Santee Cooper, adjusting startup costs in the model, refining the representation of network topology, finalizing generation resource representation, and refining modeling of hydro resources.*

7. Transmission Costs: As part of joining PJM, Duke Energy and other SC providers will be accountable for a portion of allocated Transmission cost from PJM's regional facility investment of $8 billion. Please describe why these known and accepted costs were not included in the Brattle analysis?

Brattle Responses and Clarifications: *We have added to the report discussion of the allocation of PJM regional transmission costs to South Carolina customers; see Section II.E, "RTO Implementation Considerations For South Carolina". PJM's Transmission Cost Information Center tool indicates this cost could initially be approximately $28 million, without accounting for the benefits of future regional transmission investment in South Carolina and the potential for allocation of associated costs outside the state. We also discuss in the report alternative pathways to RTO integration (e.g. a markets+ model that considers energy market integration, and a WRAP model for supply adequacy coordination), neither of which would incur any legacy transmission costs. Also see response to Dominion comment #28*

8. One-Time Costs: When joining PJM in 2010, Duke Energy in Ohio and Kentucky was responsible for one-time costs (~ $25 million). With Duke Energy Carolinas more than six (6) times the size, please describe what cost can be expected for Duke Energy customer to bear and share how that was factored in Brattle's analysis.

Brattle Responses and Clarifications: *See response to Dominion comment #12, and report footnote 75.*

9. PJM Reserve Margin: The recent Energy Transition in PJM report states that the "new low entry" reserve margin in 2030 could be at 5% based on retirements exceeding replacement generation. Please describe how the potential for low PJM reserve margins were reflected in the modeling analysis and report.

Brattle Responses and Clarifications: *We do not foresee the potential for low PJM reserve margins. The 5% number should be understood as comparable to the needs assessments that are conducted as part of the utility integrated resource planning processes, which indicate potential reserve margins subject to long-term load projections, retirements, and planned entry if no further action is taken. The 5% projection does not account for market responses or incremental utility planning that will happen in response to retirements and higher capacity prices. As PJM says in the same report, "As capacity reserve levels tighten, the markets will clear higher on the VRR curves, sending price signals to build new generation for reliability needs."[8] PJM, like every Planning Coordinator, must proactively assess reliability risk as they approach substantial fleet transition.*

As explained in our report, the PJM capacity market has consistently attracted and retained capacity supply sufficient to meet and exceed the 1-in-10 reliability standard over its fifteen year history. Under the recommendations in the report, South Carolina utilities would continue to conduct IRP processes, which would continue to be regulated and approved by the South Carolina PSC.

See also response to Dominion comment #8.

10. Retail Costs: Please confirm the level of generation additions by amount and category for each South Carolina generation unit added to the portfolio modeled that results in additional production for sale into PJM in 2030.

Brattle Responses and Clarifications: *We included planned generation resources based on information provided by the South Carolina utilities. See Appendix C, pages C-16 and C-17.*

8 https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

11. BA Obligations: It was revealed during model preparation that Brattle's modeling noticeably overstated Duke Energy Balancing Authority (BA) obligations; please describe how that was corrected in the final report; alternatively, please quantify what impact this has on results.

Brattle Responses and Clarifications: *See response to Duke comment #2.*

12. Nodal/Zonal Production Cost Modeling: On C-4 and C-5 Brattle describes PSO as a Nodal Mixed Integer model with a full nodal representation of the transmission system. Did Brattle use nodal or zonal modeling of the system for this analysis? If nodal, how did Brattle determine siting of incremental new resources, that would impact LMPs?

Brattle Responses and Clarifications: *As addressed live at the March 14, 2023 Advisory Board meeting, the model used is a nodal model. Where location information was available, we mapped new resources to their respective nodes. Otherwise, we mapped new capacity across the BAA where it would be built.*

13. Reliability Considerations: Certain existing resources require close coordination to optimize their benefit on the grid. Please explain how the study and modeling managed use of the Bad Creek pumped storage units and quantified the reliability benefits.

Brattle Responses and Clarifications: *We modeled all generation resources, including the Bad Creek pumped storage units, based on technical data provided and confirmed by Duke in written exchanges.*

Final Comments

Please see below Duke Energy's follow-up questions and additional comments for the Brattle Market Reform Confidential draft report – submitted to Brattle on Tuesday (03/21/23).

14. Reform Risk: In its report, Brattle highlighted disadvantages to South Carolina for remaining in the status quo approach but did not highlight any risk to joining PJM or creating a southeast RTO. Given industry trends that highlight reliability and resource adequacy challenges in RTO areas, PJM's recent report acknowledging likely insufficient reserve margins, and the Federal Energy Regulatory Commission's (FERC's) intention to examine the

PJM's capacity market, how will Brattle adjust its report to identify appropriate levels of risk to South Carolina for joining PJM?

Brattle Responses and Clarifications: *The report discusses disadvantages of joining an RTO in "Potential Disadvantages" in Section II.E. See also response to Dominion question 8 and Duke question 9.*

15. State Authority: With the recent complaint to the Federal Energy Regulatory Commission (FERC) by the West Virginia Public Service Commission regarding lack of access to, and representation before, the PJM Board to advocate for West Virginia customers, should Brattle's assessment identify certain customer or regulatory shortfalls of the PJM RTO system that may need to be accommodated before any recommendation to join PJM can be reasonably offered?

Brattle Responses and Clarifications: *See the discussion of disadvantages of joining an RTO in Section II.E in the report.*

16. Reliability: Although the Southeast Energy Exchange Market (SEEM) was not designed to enhance reliability or adequacy, the Brattle report suggests in its assessment that SEEM was not able to support Winter Storm Elliot but makes no mention that curtailment of firm purchased power by PJM specifically contributed to the load shed event in Duke's balancing area. With this issue highlighting reliability and adequacy challenges and generation performance issues (23% forced outage and $2 billion in looming penalties) in the PJM RTO market, what changes to the report are appropriate to recognize added risk to South Carolina customer when shortfalls occur in PJM?

Brattle Responses and Clarifications: *See response to Dominion question #20 on Winter Storm Elliot.*

17. Double Count: In its report, Brattle states that South Carolina utilities will benefit from reduced reserve margin, presumably by not having to construct all facilities in its resource plan yet calculates additional production benefit in the form of sales into PJM. Since Brattle's conclusion presupposes construction of all planned resources, please explain why its report doesn't double count capacity and production benefit.

Brattle Responses and Clarifications: *The report does not double count capacity and production benefit. As discussed in the Sections II.G and III.E in the report and live during the March 14th Advisory Board meeting, the production benefit and capacity benefit are not mutually exclusive. South Carolina customers would experience production cost savings immediately upon entering an RTO, by allowing power to flow freely across the market footprint. The investment benefit from a reduced reserve margin requirement is due to greater load diversity over a larger geographical area that would result by joining or creating an RTO. This benefit would accrue to South Carolina customers over time by avoiding or delaying capacity additions compared to the status quo.*

18. Emissions: In the Advisory Board meeting, Brattle communicated emissions were not factored into the report in any form. What updates to the report are warranted to accurately reflect emissions and any risk with production at the levels Brattle provided?

Brattle Responses and Clarifications: *The cost of emissions are included in the modeling effort. See response to Duke comment #4.*

19. PJM Market Pricing: The most recently issued independent monitor 2022 State of the Market Report for PJM indicated:

- "Energy prices increased significantly in 2022 from 2021. The real-time load-weighted average LMP in 2022 increased 101.4 percent from 2021, from $39.78 per MWh to $80.14 per MWh. This was the highest average PJM price ($80.14 per MWh), the highest price increase ($40.36 per MWh) and the highest percent price increase (101.4 percent) for a year since the creation of PJM markets in 1999."
- With this new information revealing rapid energy price escalation, what additional customer cost sensitivity should be factored into the Brattle analysis, either quantitatively or qualitatively to represent this real and meaningful risk identified by the market monitor?
- PJM Reserve Margin: The recent Energy Transition in PJM report states that the "new low entry" reserve margin in 2030 could be at 5% based on retirements exceeding replacement generation. During the recent 3/14/23 Advisory Board Meeting, Mr. Andrew Levitt indicated his opinion that PJM reserves would not be allowed to reach 5% because the price signal would rise, resulting in an increase in available reserves. Please

describe how the potential for low PJM reserve margins were reflected in the modeling analysis and report.

Brattle Responses and Clarifications: *Market prices in PJM in 2022 reflect the high volatility in natural gas prices observed in the last year. The market prices in our simulation reflect the long-term fuel price forecasts used in the model, which were provided by the Advisory Board members. See response to Duke comment #9 on PJM future reserve margins.*

20. PJM Interconnection Queue: How does Brattle suggest utilities will get new renewable generation online given the interconnection queue issues and suspension for facilities in PJM?

Brattle Responses and Clarifications: *See response to Dominion comments #5 and #6 above. Note that EIA projects over 4,000 MW of solar and wind will come online in PJM during 2023.*[9]

21. Benefit Mismatch: Given the level of export sales from South Carolina providers into PJM, capacity challenges and the energy price escalation noted above, is it appropriate for the South Carolina Market Reform Study Committee to conclude PJM receives a greater benefit from Duke Energy and South Carolina utilities joining PJM than the South Carolina customers will benefit from any affiliation with PJM?

Brattle Responses and Clarifications: *No, all modeling results summarized in the report are benefits for South Carolina. Our modeling also showed that the South Carolina (and the Carolinas as a whole) benefitted more from joining PJM markets than PJM would benefit. This is largely because the Carolinas would get access to a larger market with greater diversity, while the diversity benefits of adding the Carolinas are much smaller to PJM (as it is already a large regional market).*

22. Calibration: During the last advisory board meeting before Brattle released it's preliminary report, it was revealed that the Market Reform Study evaluation model Brattle produced was never able to accurately predict a known past reference year as expected. Please explain the range of impacts this known model challenge had on the study evaluation

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[9] *See EIA's Preliminary Monthly Generator Inventory for February 2023: [https://www.eia.gov/electricity/data/eia860m/.](https://www.eia.gov/electricity/data/eia860m/)*

results and how Brattle's set of recommendations was influenced. Additionally, should this calibration challenge be highlighted within the quantitative section of the report?

Brattle Responses and Clarifications*: See response to Duke comment #6.*

23. Energy Efficiency: Please describe how Brattle factored existing state laws/regulations, which provide for utilities offering energy efficiency programs to receive full recovery and incentives sufficient to ensure that the net income of a utility is at least as high as the net income would have been if the programs had not been implemented, into its evaluation of the need for third party EE administration in SC.

Brattle Responses and Clarifications: *Our recommendation is that South Carolina lawmakers authorize the PSC to appoint a third party EE administrator "in utility territories where substantial cost-effective EE opportunities exists to reduce customer electricity bills but that have not been fully pursued under existing structures." That would allow the PSC to determine if such an appointment was necessary for a utility given current energy efficiency programs and existing laws and regulations in the state.*

24. Demand Response: Currently Duke Energy (DEP and DEC) demand response programs are offered across state lines to customers, which makes aggregation more complicated and perhaps, infeasible. Please describe what analysis Brattle performed to mitigate this concern before promoting aggregation as a recommended course.

Brattle Responses and Clarifications: *There is no recommendation in the report to require DER aggregation for existing programs. We do recommend to continue pursuing innovative utility rate structures and RTO participation models that can enable more DERs, whether aggregated or not aggregated.*

25. Third-Party Administrator: On pages 141-142, the report references states with third-party administrators such as New York, Wisconsin, and Vermont as models for the success South Carolina could achieve under a similar structure. Please describe what steps Brattle took to ensure that comparisons between those states and SC were accurate, such as reviewing annual performance reporting by utilities with net savings isolated (rather than gross) and reductions from renewable programs excluded.

Brattle Responses and Clarifications: *References to those states appear in the section titled "Description and Relevant Case Studies." They are meant to provide examples of other states that have pursued these policies, there is no analysis conducted that indicates benefits would be the same, smaller, or larger in South Carolina. The PSC could analyze these questions once authorized to appoint a third-party EE administrator, if it is deemed to be needed.*

26. Third-Party Administrator: The report states that one of the potential disadvantages of switching to a third-party administrator is the potential of losing "established infrastructure, experience, and customer relations that already exist within the utility." How did Brattle quantify the value of existing utility programs and the impact of dismantling them in its analysis prior to recommending the state adopt a third-party EE administrator?

Brattle Responses and Clarifications: *This comment mischaracterizes the recommendation made in the report. The recommendation is that the South Carolina lawmakers authorize the PSC to appoint or create a third-party EE administrator "in utility territories where substantial cost-effective EE opportunities exists to reduce customer electricity bills but that have not been fully pursued under existing structures." Once authorized to consider appointing a third-party EE administrator, we would expect the PSC to consider all the related costs and benefits.*

27. Energy Efficiency: In its report, Brattle provides benchmarks that suggest SC could, like Wisconsin, deliver $1 billion in economic benefits over a sufficient time frame with $4.36 in benefits for every $1 invested with third-party EE administration. From 2017-2022, Duke Energy achieved nearly $2 billion in savings (both bill savings and avoided costs) in South Carolina and $5.18 in benefits per $1 invested in EE. Please describe how Duke's program performance was factored into Brattle's recommendation to adopt third-party EE administration.

Brattle Responses and Clarifications: *See responses to Duke comments #23 and #26.*

28. PJM Uplift Costs: In an Electric Energy online article, The Bigger Picture | FERC Requires Greater Transparency Regarding RTO/ISO Uplift, there is discussion about out-of-market costs in RTOs and lack of cost transparency to these additive costs. Please comment on what qualitative discussion Brattle should include in the report to describe the additional cost risk to customers for out-of-market costs not reflected in the study.

Brattle Responses and Clarifications: *Uplift costs are included in the Adjusted Production Cost (APC) metric used to determine benefits of market participation. Uplift costs in PJM are allocated by utility zone to cover fuel costs in the same zone, so those costs do not present any risks to utility customers that they do not already face.*

29. Failing RTO Capacity Markets: Several FERC commissioners and independent market monitors have raised concerns about RTO reliability and forward capacity markets, suggesting these markets are not providing value to customers. With concerns of inadequate and failing capacity markets, what qualitative discussion should be included in the Brattle report to highlight the severe risk to customers and the long-term negative effect on reliability or resource adequacy?

Brattle Responses and Clarifications: *Our views on the performance of capacity markets are nuanced and vary by jurisdiction. For the purposes of this report, we have focused primarily on describing the advantages and disadvantages of the PJM capacity market given the RTO configurations selected in consultation with the Study Committee and Advisory Board, as well as focusing on WRAP-style pathways for supporting resource adequacy in a coordinated fashion but without an organized capacity market. In both cases, we disagree with the question's assertion that the market is failing or that reliability is at risk.*

We do confirm and emphasize our view that resource adequacy structures (whether supported by utility planning, WRAP arrangements, or a centralized capacity market) will need to be substantially enhanced over the coming decade to most effectively account for and rely on emerging technologies including renewable supply, batteries, DERs, and demand response. These resources can provide reliability value, but traditional approaches to assessing and utilizing that reliability value must be continuously improved if they are to provide a sizeable share of the energy supply mix. This challenge affects utilities in RTO and non-RTO regions alike. However, the opportunities to more cost-effectively meet this challenge in a regionally coordinated fashion is one of the primary reasons that 22 investor-owned and publicly-owned utilities across the West have already committed to join the recently-organized WRAP.[10]

See Report Section III.E. See also response to Duke comment #9.

Follow up Questions from Advisory Board Meeting

[10] ER22-2762_WRAP_Tariff_Filing.pdf (westernpowerpool.org)
WPP (westernpowerpool.org)

30. Transmission Costs: In discussions in the most recent Advisory Board meeting (03/14), Brattle suggested PJM Transmission costs were mostly local. As a member of PJM in its Midwest service areas, Duke is familiar with assignment of Transmission costs and notes that 50% of RTO transmission is allocated to participants. As part of joining PJM, Duke Energy and other SC providers will be accountable for allocated Transmission cost from PJM's regional facility investment of $8 billion that could be as much as $60-$70 million annually. These costs appear not to be reflected in the Brattle report either quantitatively or qualitatively.

Brattle Responses and Clarifications: *Added discussion in the report, including reference to an indicative estimate of $28 million annual transmission costs. See footnote 906 in the Report.*

31. One-Time Costs: When joining PJM in 2010, Duke Energy in Ohio and Kentucky was responsible for one-time costs (~ $25 million). Based on the Carolinas footprint, Duke Energy and other South Carolina utilities could be responsible for between $290-$300 million in initial costs that have not been reflected in the Brattle report either quantitatively or qualitatively.

Brattle Responses and Clarifications: *See response to Dominion comment #12, and report footnote 75.*

32. Capacity Benefit: In its report, Brattle appeared to calculate a high-capacity benefit by assumptions that all capacity above a 14.7% reserve margin would clear into the capacity market at the highest cost of new entry value and a high peak load diversity. Using a more reasonable diversity of 2.7 percent and more reasonable capacity cost assumptions, Duke calculated the capacity benefit to only be $32 million based on Brattle's approach.

Brattle Responses and Clarifications: *This comment misrepresents the analysis conducted to determine the investment cost savings from joining an RTO. The calculation of the investment cost savings shown in Table ES-1 does not assume any South Carolina resources clear the capacity market in PJM. In fact, that analysis of investment cost savings does not assume South Carolina utilities participate in the PJM capacity market. See response to Duke comment #1.*

A separate analysis, discussed in Section III.E, estimates the benefits for South Carolina customers from transitioning to competitive generation supply investments. The benefits calculated in this analysis includes additional cost savings from moving to a competitive supply *investment mechanism that are additive to the investment cost savings from joining an RTO shown in Table ES-1.*

We estimated peak load diversity using historical data from 2011-2021 from FERC Form 1.

Lockhart Power

Bryan Stone, President, Lockhart Power Company

Lockhart Power Company has a unique position within the South Carolina electric utility industry. It is privately owned by the Milliken family, which has exceptionally high environmental and community values. While it is an investor-owned utility (IOU), it is the only IOU in SC that is not a Balancing Authority (BA), and it has no transmission system since it distributes power at a sub-transmission voltage level. Lockhart Power has a number of renewable generation facilities, but no nuclear or fossil fuel power plants. It has a smaller, rural customer base, and tends to work closely with its customers. As a result of these characteristics, Lockhart Power believes it offers a reasonably objective perspective regarding wholesale market reform. Lockhart Power's main objectives as a member of the Advisory Committee are to help ensure the integrity and accuracy of the EMRM process, including that the benefits and risks of each alternative are clearly identified. Our main priority is that we are able to continue to reliably provide power to our customers, in the face of climate change and resulting increasing storm severity, as well as the transformational changes our power grid system is expected to undergo during the decarbonization process over the next 20-30 years. The cost of power is very important, but should not come at the expense of reliability.

In general, Lockhart Power has questions and comments about the draft report language related to the following main themes: how the Southeast Energy Exchange Market (SEEM) is discussed, the timing, cost and risks of transitioning to another market structure, the impact of reducing generation capacity reserve margin on reliability in a worst-case severe storm scenario, and the loss of state and local utility control under alternate market structures. Additional issues are addressed as well. It is Lockhart Power's hope that The Brattle Group will carefully consider how to address these issues in the final version of the report, along with issues raised by others in the Advisory Committee, to yield a balanced and objective result:

1. Expected Cost Savings
    a. How much are the savings for each scenario in $/kWh, and on a percentage basis? For example, the report gives the potential value of joining PJM as $285-362M/year. While

this is a lot of money on an absolute dollar basis, when the midpoint of this range is spread across the 78 TWh of annual electric power consumption in South Carolina (https://www.energy.gov/sites/prod/files/2015/06/f22/SC_Energy%20Sector%20Risk%20Profile.pdf), it would equate to about 0.4 cents/kWh. If an average SC residential customer bill is 14.32 cents/kWh (https://www.eia.gov/state/print.php?sid=SC), that is about a 2.9% decrease in residential rates. There should be this type of explanation of the relative savings, so that policy makers can decide whether the effort, disruption, unintended consequences and other forms of risk of transitioning to an RTO is worth less than a 3% rate decrease at some point in the future.

Brattle Responses and Clarifications: *As mentioned in the report, the observed operational benefits from participating in RTO energy markets have been in the range of 4%-8% in other regions. See discussion of production cost savings in the Executive Summary of the report.*

b. How long is each scenario realistically expected to take to implement?
c. For each scenario, would bills rise in the nearer-term due to transition costs, then presumably decline once the larger cost benefits begin to be achieved?

Brattle Responses and Clarifications: *The Executive Summary and Section II of the report provide implementation timelines for the various wholesale market reform options. Integrations into PJM have been accomplished in about 18 months, setting up a new EIM or RTO would take longer. For any costs incurred during the transition, it would be up to the South Carolina PSC to determine how and when they are incorporated into rates.*

Reducing Reserve Margin

2. Describe in simple terms (perhaps by pie chart) how much of each asset class is currently in the Reserve Margin part of the dispatch stack for the 4 BA utilities (e.g. CT's, diesel peaking, third party generation assets, battery, pumped hydro, DSM, etc.), and is any of it intermediate generation (e.g. NGCC)? Is any of it purchased power from off-system (e.g. PJM), which may not be available in a widespread regional emergency event?

Brattle Responses and Clarifications: *See Appendix C.*

3. The concept of reducing reserve margin appears to be the largest contributor to the projected savings of joining an RTO – the report should quantify how much of the savings it represents in both the "Join PJM" case and the "Create SE RTO" case.
   a. During the 2/14/23 Advisory Group call, a comment was made that RTO's typically have a 15-18% reserve margin, and a separate comment was made that PJM has about 17%, and that 14% was assumed for SC in the study. These should be clearly presented in the report; for example, if PJM has a 17% reserve margin, why would we assume SC savings associated with 14%?
   b. Per Page 84 of the draft report, if a 14.7% planning reserve margin is being assumed for the "Join PJM" scenario, what is the basis for that assumption? Per the following linked article, PJM's current reserve margin is 23%, so why the large difference? (https://www.utilitydive.com/news/pjm-capacity-market-reform-reserve-margin/643598/#:~:text=Under%20a%20%E2%80%9Clow%E2%80%9D%20new%20entry,2028%20and%2015%25%20in%202030)
   c. The same article above indicates that "Under a 'low' new entry scenario, PJM expects its reserve margin will plunge to 8% in 2028 and 5% in 2030". This seems like a significant risk that should be discussed in the report, along with any measures our system might be able to take to protect our residents and businesses.

Brattle Responses and Clarifications: *Table ES-1 breaks out the estimated net benefits by category, illustrating how much of the benefit comes from the investment savings due to a reduced planning reserve margin. PJM has a target planning reserve margin of 14.7%, while the South Carolina utilities have a target reserve margin of 17% (based on most recent IRPs). This planning reserve margin can be different from the realized reserve margin due to changes in the peak load forecast and if some supply is retained in the market beyond what is needed for reliability. The target planning reserve margin is the appropriate number for calculating investment cost savings, as members in PJM would be required to plan to that target under the Fixed Resource Requirement Alternative (i.e. the model in which utilities can participate in resource adequacy coordination without participating in the capacity market).*

See also responses to Dominion comment #8 on PJM current reserve margin and Duke comment #9 on PJM future reserve margins.

4. The report should address the concept that reducing reserve margin is not a "Free" savings - it comes at the cost of increased outage risk (i.e. reduced resiliency), versus having more generation capacity in reserve, and it can only be achieved in a risk neutral manner if there

is sufficient transmission interconnect and generation capacity at multiple points to allow power flow from a system with excess generation to a system with a generation shortage during emergency events. Also, during the Brattle call discussing the draft report, Brattle stated they really haven't studied the cost to add transmission interconnect capacity; if not, how do we know the time and cost to expand it in order to obtain the estimated benefits of reduced reserve margin? If that is an area that requires more study if an RTO option is to be considered, then that should be specifically stated in the report.

a. How does Brattle decide what an acceptable reserve margin is for use in its model? Does that reserve margin correspond to an outage probability, e.g. if a 20% reserve margin avoids outages for up to a 100-year weather event, does a 15% reserve margin avoid outages up to a 10-year weather event? If a given level of reserve margin cannot be tied to the probability of a widespread outage, how do we know how low we can bring the reserve margin without taking unreasonable risk? Does Brattle think that a 14.7% reserve margin for the "Join PJM" and "SE RTO" scenarios is the same level of outage risk as the higher reserve margins the smaller utility systems have today, or a lesser risk of outage, or a higher risk of outage?
b. Pg. 83, first full paragraph – to what does "same reliability standards" refer? Is there a specified reliability standard in place today that will be matched, or is this saying that whatever the current reliability level is, joining the PJM RTO and decreasing the reserve margin by 6.6% will maintain that same level? If the latter, does this imply that Brattle believes the current reliability level within PJM is acceptable going forward?
c. What would happen in an RTO scenario when a "congestion" condition prevents power from flowing into SC during an emergency weather event, and SC's reserve margin resources within the state had been lowered and were unable to serve the load? For example, in the "Join PJM" scenario, what if a regional ice storm hit the Carolinas and the PJM mid-Atlantic region, and the mid-Atlantic region needed power even more than the Carolinas and therefore their resources were unavailable to us, and we were stuck with a lower native reserve margin than we have today (when today's reserve margin was insufficient in December 2022).
d. Reduced resiliency – in general, the trade-off between reducing reserve margin and resiliency deserves being described in its own section to fairly represent the pros and cons of reducing reserve margin. The current description appears somewhat over-simplified, because it implies that a given reserve margin can be "dialed in" and maintained over time, when the above linked article highlights how much it can move within even a few years, with the RTO having limited ability to prevent such movement.

e. If there are fewer excess generation assets (i.e. lower reserve margin) under an RTO scenario, is there an opportunity cost of not being able to add certain types of very large-load customers in the short-term (since that could further reduce reserve margin to unacceptable levels), thereby reducing economic development opportunities?

Brattle Responses and Clarifications: *Reserve margins are determined by planners coordinators according to probabilistic analysis of the applicable region. The reliability standard is "1-in-10", which means 1 shortage event in 10 years. See NERC standard BAL-502-RF-03. As addressed live at the March 14, 2023 Advisory Board meeting, the reduced planning reserve margin that would be enabled by a larger regional footprint does not imply an increased risk of outages. As a member of an RTO, South Carolina utilities would be able to satisfy the same reliability standard (i.e., the 1-in-10 reliability standard) at a lower planning reserve margin due to the increased load diversity and resource diversity that results from pooling resources over a larger geographic area. This means that utilities could build fewer generation resources and still achieve the same level of expected shortage-related outages. Chairman Thomas of the Arkansas PSC provided the Study Committee with a clear explanation of the benefits customers in his state have experienced due to this fact. See his comments to the Study Committee on September 1, 2022. See also response to Dominion comment #11.*

See response to Dominion comment #27 on transmission investment.

5. Climate change considerations – The increasingly extreme weather strains our existing reserve margin resources, as demonstrated last December in Duke's system, and the time required to add generation resources is increasing due to supply chain, interconnection approval, and other issues within our industry. Extreme weather systems tend to affect our entire region – PJM in particular is often impacted even more than the Carolinas. Given all of this, isn't reducing our native (local) reserve margin moving in the wrong direction?

Brattle Responses and Clarifications: *As described in the response above, in a larger regional market it will be possible to set a lower planning reserve margin and achieve the same level of resource adequacy reliability in South Carolina.*

We do agree that all utility and RTO systems must continuously enhance their ability to accurately assess, measure, and enforce their resource adequacy standards in the context of resource transition and exposure to extreme events. See also response to Duke comment #29.

6. How much physical transmission system interconnection exists today between SC, NC and PJM, and between SC and neighboring utilities? (Provide a map with capacity at each interconnect location and estimated total capacity to PJM pathways and other systems/utilities).

Brattle Responses and Clarifications: *The transmission topology we used in the model came from the Multiregional Modeling Working Group 2018 power flow case for peak summer 2020 conditions, and we confirmed the modeled transmission rights between the four South Carolina BAAs and their neighboring utilities with each utility member of the Advisory Board. We do not have a map that shows all the interconnection locations and points between the South Carolina utilities and their neighboring utilities. PJM analysis shows the following Total Transfer Capability values from PJM to the following:*[11]

- *PJM to Duke Progress East (CPLE): 1,377 MW*
- *PJM to Duke Progress West (CPLW): 690 MW*
- *PJM to Duke Carolinas: 2,200 MW*

7. How much new transmission construction (GW's and $) would be needed in order to be able to safely assume that peaking resources in another system (e.g. PJM) would be available in a worst case weather event, and allow us to achieve the savings associated with the proposed reserve margin reductions? Is this cost discussed in the body of the report and the Executive Summary?

Brattle Responses and Clarifications: *See response above, the analysis in the report assumes the existing transmission infrastructure. If new transmission is built, it will increase the benefits calculated in the report. There is over 4,000 MW of import capability from PJM to the Duke utilities, so PJM analysis of required transmission is unlikely to identify any needed transmission upgrades to meet transmission reliability planning standards.*[12] *In the context of resource adequacy, PJM's resource adequacy structure stipulates total capacity requirements, and also imposes transmission limits that ensure each subregion or "Locational Deliverability Area" has sufficient locally-sourced capacity. Upon initially joining PJM, we anticipate that South Carolina utilities would be net sellers of capacity (earning net revenues that can be returned to customers). Over time as needs arise, South Carolina utilities could choose to procure a portion of their capacity needs from other utility areas, but could never rely on capacity purchases beyond what can be supported by the transmission system.*

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[11] https://pjm.com/-/media/committees-groups/committees/pc/2021/20210827-workshop-4/20210827-item-04-data-analysis-presentation.ashx

[12] *Ibid*.

8. Pg. 65 – If SC tries to join PJM without NC, “Establishing firm transmission from SC to PJM would likely be necessary…” – at how many points, at what cost, how long would it take, and who would pay for it? Shouldn’t this be described as a major impediment to pursuing PJM membership without NC, and if so, since a Brattle recommendation is to pursue PJM membership ASAP, does that entail getting with NC ASAP to discuss that?

Brattle Responses and Clarifications: *This comment misstates the recommendations in the report. The report does not recommend South Carolina pursue “PJM membership ASAP.” The report recommends that South Carolina either create a new Southeast RTO market or “Join an existing RTO (e.g., PJM), <u>coordinating with North Carolina policymakers,</u>” and it states that “It is theoretically (<u>but likely not practically possible</u>) that Duke’s South Carolina territories could join PJM without the North Carolina portion” (emphasis added).*

9. If SC joins an RTO, reduces its reserve margin to save money, and builds transmission interconnect capacity to allow enough generation to flow into SC from PJM to replace the reduced reserve margin capacity, if a severe winter storm hits the Carolinas and adjacent southern part of PJM, how can we count on PJM generation flowing to us, or how can they count on it flowing from us to them? As severe storms become larger and larger due to climate change, can’t they cover entire regions and eliminate the benefit of regional geographic diversity in a worst-case scenario?

Brattle Responses and Clarifications: *See response to reserve margin comment above and Dominion comment #20 on RTO resiliency to extreme weather events. As described in response to Lockhart Questions #4 and #7, PJM performs probabilistic analysis to ensure that there is enough local generation and transmission to meet emergency needs.*

10. During the Advisory Group call on 3/14/23, a comment was made that the PJM queue is about 3-5 years, presumably to get approval to interconnect new generation once it is built. Does that imply that new generation has a 5+ year lead time from when the need is identified, and if so, if we reduce our reserve margin to 14%, what happens if we add significant load via new customers, existing customer load growth, transportation electrification, etc. and have to wait that long for new capacity, shouldn’t that push the near-term target reserve margin higher than historical targets?

Brattle Responses and Clarifications: *Under the recommendations in the report, even after joining an RTO the South Carolina utilities would continue to plan and build for their systems under the existing IRP process, with oversight from the PSC. The IRP process would continue to ensure that the utilities are building enough resources to serve projected load, with the PSC continuing to regulate. The IRP processes look ahead ten or more years to plan new resources, which would not change under the recommendations made in the report.*

SEEM

11. Since SEEM is brand new, what key assumptions were made in modeling its impact on the status quo case, including economic savings? How can these benefits be estimated with confidence, since SEEM is so new and benefits have not had a chance to develop yet? When does Brattle estimate that most of SEEM's eventual benefits will have had a chance to manifest in the market?

  a. Page 4, last line – it says a portion of regional benefits are already accounted for in the status quo scenario – which benefits, how much in related savings are included, and is this amount consistent with what the SEEM constituents expect to achieve? If SEEM constituents expect materially different benefits than are modeled in this report, that difference should be presented and discussed in this report for full transparency.
  b. Pg. 19 – Isn't SEEM an "organized regional market with transparent price signals"?
  c. Pg. 34, paragraph 1, last sentence – The concept of eventually evolving SEEM into an RTO is discussed here, and in general the concept of developing a SE RTO is discussed in the body of the report. Why isn't this included in the Executive Summary (Pg. 12-13) list of recommended options for SC policymakers to consider? It would appear to be a legitimate option, since it would retain more control during and after a transition period and therefore could be considered to be a more cautious/conservative approach. In other words, given the comments in the report about all other RTO's having evolved from more humble beginnings over many years, isn't it reasonable for the purposes of this report to assume that developing a SE RTO would in all likelihood involve having SEEM evolve into an RTO over time? If so, the report structure could be simplified and made easier to follow by not treating SEEM and a SE RTO as two separate paths.
  d. Why isn't there a separate section devoted to describing SEEM? It is currently just part of the general description of the status quo case (Pg. 35-36), but it merits its own section given its current and potential future role in wholesale market reform. For example, the cost-savings features merit more discussion, including no transmission costs and splitting savings on transactions (are there others?).

e. If SC joined PJM as Brattle gives for its first recommendation, what would happen to the SC IOU's involvement in SEEM?

Brattle Responses and Clarifications: *There is a description of the cost-saving features of SEEM in the Status Quo section of the report. We modeled it as part of the Status Quo, and our model simulates more than ten times as many transactions in the SEEM as there have been since its implementation (see Appendix C). Therefore, our implicit assumption is that operation of the SEEM will become significantly more efficient over time, and more economic power transactions will take place through the SEEM, than experienced to date. This assumption implies that our estimate of benefits for the SEEM is several times larger than experienced by participants to date, and takes into account significant maturation of the SEEM. The option to evolve the geographic footprint of SEEM into an RTO is one of the recommendations made in the report (the Southeast RTO option). South Carolina policymakers and stakeholders will need to decide whether pursuing membership in an existing RTO or creating a new one out of the SEEM footprint (or part of the SEEM footprint) is a better option for South Carolina. In our model, SEEM continues functioning in the case where the Carolinas join PJM, but without the Carolina entities.*

Control

12. If SC implements an energy policy requiring a notable transmission expansion and SC was part of an RTO (e.g. PJM), what influence would it have over IOU's/PJM to move them toward that expansion ASAP, as compared to the amount of influence it has today with SC IOU's? Joining an RTO would appear to reduce SC's ability to create a competitive advantage over neighboring states if it decided to pursue an aggressive energy policy.

   a. The PJM Board of Managers (per its web site https://www.pjm.com/about-pjm/who-we-are/pjm-board) has 10 members, who are required to be unaffiliated with any PJM market participant. Most are apparently from other parts of the country. How are they supposed to understand and prioritize the needs of the SE when they have little (if any) experience in the region?

      i. The one exception is Terry Blackwell, former SVP of Santee Cooper – but wouldn't he be required to resign if SC joined PJM?

Brattle Responses and Clarifications: *If South Carolina utilities joined an RTO, policymakers in the state would continue to have authority over energy policy for the state. Furthermore, under our recommendations, the PSC would continue to regulate the IRP processes of each utility. None of these functions would be subject to the PJM board if South Carolina decided to join PJM. For regional transmission expansion specifically, PJM has a mechanism called the "State*

Agreement Approach" to facilitate transmission-related aspects of state energy policy, as recently demonstrated in New Jersey, and state agencies coordinate on transmission policy through the Independent State Agencies Committee and Organization of PJM States, Inc. Finally, South Carolina utilities have the option to pursue the creation of a new RTO in the Southeast, with new governance structures.

Risk (other than Reducing Reserve Margin)

13. Pg. 21 - If Act 187 stated that this report should address the question of how market reforms can "protect consumers from excess risk", shouldn't there be a detailed Risk Analysis section of this report?

14. Pg. 27 – The main risk mentioned is that outsourcing generation supply shifts investment risks to resource owners. What about the other side of the equation, i.e. if other resource owners default on agreements in an emergency or don't invest enough to ensure reliability in extreme weather events (e.g. Texas 2021 winter storm), doesn't this just swap investment risk for operational risk?

Brattle Responses and Clarifications: *Each market reform option is described with advantages and disadvantages to highlight potential risks of each option. This comment misstates the recommendations of the report. We do not recommend eliminating the resource adequacy requirement (as was done in Texas), and we do not recommend to pursue generation divestiture or competitive investment restructuring at this time.*

Appearance of Potential Bias

Without implying whether there is any form of actual bias within the report, some readers may be looking for any appearance of bias; therefore, it is important that the report avoid even the appearance of bias in order to receive full consideration.

15. After one careful read of the draft report, the following are some areas that stood out and which might be addressed to head off potential issues:

   a. The report consistently paints a rosy picture for joining an RTO, with PJM at the top of the list; however, there is no detailed list of cons or risks associated with this option. A thoughtful list of potential downside considerations should be included if the report is to be taken seriously as an objective evaluation. This could be through a "Risk Analysis" section as mentioned above.

b. Are PJM or other RTO's facing any significant issues, and if so, shouldn't those be at least mentioned in this report as potentially indicative of what we might face if we joined an RTO?
c. Pg. 35, last paragraph and Pg. 36 – Why does the description of SEEM focus almost entirely on what it is not designed to do, and only the last sentence says anything positive about it? Since Page 36 begins with a list of what "SEEM has been criticized for", why isn't there a similar paragraph (or more) for the PJM RTO alternative? During the Advisory Board call on 2/14/23, a suggestion was made to only include the SEEM disadvantages in the list of RTO advantages – I think this is a good suggestion, and may remove some of the appearance of bias against SEEM.
d. Pg. 55, paragraph 2: "While all RTO's yield large net benefits…" – Is this a documented fact, or a contested opinion? It is being presented as the former.
e. The recently added consultant at the Brattle Group, Andrew Levitt, initially introduced himself by email to the Advisory Group as one of the authors of the report. In looking into his background, he apparently was recently Senior Market Strategist at PJM Interconnection, where his role included assessing "emerging technologies for strengthening PJM markets". (https://www.youtube.com/watch?v=Jm10-p2NdQg)
f. If so, and he left PJM just a few months ago to work for Brattle in co-authoring this report, then it raises an obvious question of potential bias in the report toward the PJM option. This may merit some form of commentary to explain this key addition to Brattle's team late in the study process.

Brattle Responses and Clarifications: *Edited report in response to comments. There is a list of disadvantages provided in the report for every reform option considered, including membership in an RTO, which highlight the risks associated with those reform options and issues faced by jurisdictions that have adopted those reforms.*

Our recommendations are based on the results of the analyses presented in the report. The analysis finds benefits from joining PJM (fully or partially), creating a new Southeast RTO, forming an EIM in the Southeast, or forming an expanded JDA across all four BAAs. We find that the most beneficial option for South Carolina customers is for the state to pursue membership or integration with an existing RTO or creation of a new RTO.

16. Competitive Investment Reforms

a. The concept of developing resources should be considered as having two components that are separately evaluated: the cost to develop, and the cost recovery mechanism.

i. Cost to Develop – Utilities should look for low-cost providers of new resources (as the draft report supports), for example who can build a 75 MW solar project on a given site for the least total connected cost.
ii. Cost Recovery Mechanism – Comparing a levelized cost to purchase power to the cost to rate base a new resource is like comparing apples to oranges. The rate base approach is front-end weighted, so its nearer-term financial metrics will generally not be as good as a levelized approach. However, the financial impact later in the project life will be better, since the resource will be mostly depreciated and ROE will be very low in dollar terms. Also, a levelized cost may assume ownership is retained by the IPP, whereas it would need to be retained by the IOU for an equitable comparison.

b. There is not any discussion of why IPP's may be able to provide power at lower costs than utilities; rather, it seems to be a general assumption that competition will lead to lower prices. There should be some general discussion of this topic, including the following:
   i. What does Brattle believe the source of IPP's cost advantage to be?
      (1) Are IPP's willing to accept lower risk-adjusted returns than IOU's?
      (2) Do IPP's have better economies of scale or other efficiencies in developing and/or operating resources than IOU's?
      (3) Other?
   ii. If IPP's did have any of the above cost advantages, why couldn't an IOU just pay them to develop and/or operate the resource under the IOU's ownership and control, so the IOU continues to be fully accountable for performance, including reliability?

Brattle Responses and Clarifications: *See discussion of potential advantages in Section III.E. Competitive investment reforms can attract new suppliers and technologies, allowing all potential supply resources to compete and drive down costs. The report recommends that South Carolina require utilities to increasingly incorporate competitive solicitations in their IRP processes, which is consistent with the suggestion that utilities look for low-cost providers of new resources.*

17. Environmental

a. Pg. 80 – "In the PJM case, coal generation output increases." Isn't this a con that should be mentioned along with the pros, perhaps on Page 61 under "Potential Disadvantages"? For some stakeholders at least, this could be a major concern.
b. Does the model include assumptions/calculations for how much new generation by resource type would be added under each scenario, to give a sense of how renewable development would be impacted by market structure chosen?

Brattle Responses and Clarifications: *Please see additional materials added to Appendix C. In the PJM market participation case, coal generation increases in the Carolinas footprint, but it decreases across the entire PJM footprint and across the entire simulated footprint in our model. We assume that only resources in the utilities' existing resources plans will be built by 2030. However, IPP-owned renewable development has been historically faster in RTO markets. See response to Duke comment #4.*

18. Other

a. Pg. 5, Last paragraph, first sentence – please define what "increased liquidity" means in this context.
b. Pg. 14 paragraph 1 – large IOUs already offer a wide variety of rate choices – if this paragraph is geared more toward smaller utilities, it should state so.
c. Pg. 16-17 Offering full retail choice has additional risks that are not included, but should be. For example, for smaller utilities with higher embedded costs, if they lose load to competition, their rates will increase further in order to recover costs from less sales volume, potentially creating a snowball effect of cascading customer losses. At some point, this could cause utility failures (like a bank failure), including for municipal electric utilities and rural electric cooperatives – who may be buying power from the same larger utilities against whom they would be competing.
d. VACAR-South – Why is this only mentioned once (Pg. 35) and in the body of the report, and not also in the Executive Summary along with SEEM and JDA as being one of the existing regional measures SC participates in for reliability and to control costs by sharing resources? Doesn't it merit a little more description in the body of the report about what it is, what it does, and the related benefits?
e. Pg. 37-38 – One of the most important advantages of the Status Quo: Accountability! Yes, utilities have "significant autonomy and discretion" as the first bullet states, and because they have this level of control, they are able to be held completely accountable for overall performance by the PSC, legislators, and public at large. This provides an important public benefit since utilities know they cannot point the finger at an RTO or

another entity in case of transmission constraints or other issues. Because the PSC and legislators have control over the utilities, they also have a large measure of control over certain areas of utility performance. This control is diminished as regionalization increases. For reference, see Pg. 61 "Potential Disadvantages" of joining an RTO – the first bullet states that that being part of an RTO "requires compromises to achieve consensus."

f. Pg. 38 – "Disadvantages of Status Quo Approach", bullet 1: "Administrative costs may exceed the operational savings" – Is this referring to the administrative costs of SEEM? If so, some of the SEEM members may disagree (strongly), and they should be given a chance to provide information regarding this point.
g. Pg. 61, last paragraph – Since Duke Energy (Ohio and Kentucky) just joined PJM a decade ago, was anyone involved in that integration at those utilities interviewed to get their thoughts about how challenging the transition was, whether their customers were better off, pros and cons, etc.?
h. Pg. 62, first full paragraph – Does the $1M integration cost include legal, regulatory, consulting, adding and training personnel, equipment, and other costs? The footnote references the EKPC utility - has Duke verified this was similar to their experience and cost for Duke Energy Ohio and Kentucky? Is there any information available for what the cost would be for smaller utilities like Lockhart Power with no transmission assets, but generation assets? (This last question may have been answered on the last Brattle call by Duke, which said their cost was about $25M – for one or both utilities?)
i. Pg. 68, main paragraph, last sentence, including footnote 93
    - **i.** Do the SC BA's generally agree with the footnote 93 assertion that "only two regional transmission projects have been identified in the SERTP planning process since 2014"?
    - **ii.** If so, is their opinion that the reason is because there is no compelling need, or that the lack of an RTO structure is a barrier to achieving economic and/or reliability benefits that would be available under an RTO structure, or some other reason?
j. Pg. 82, first full paragraph – The recommendation that if readers of this report adopt your recommendation to join PJM, they should further study the RTO benefit analyses, should be included in the overall recommendation to join PJM that appears elsewhere in the report, including in the Executive Summary. The recommendation to study an RTO structure further is materially different than a recommendation to join PJM. Brattle's actual recommendation in this regard should be clear throughout the report.

Brattle Responses and Clarifications: *We addressed and answered several of these comments in the final draft.*

19. Typos – Just a few minor observations for your use:

a. Pg. 14 paragraph 1, next to last line – “cost-shifted” → “cost-shifting”
b. Pg. 21 paragraph 2, Line 5 – “reform” → “reforms”
c. Pg. 34 “overtime” → “over time”
d. Pg. 35 “minutes-to-minute” → “minute-to-minute”
e. Pg. 37 “customers rate adjustment” → either “customers’ rate adjustment” or “customers via rate adjustments”
f. Pg. 53, 1st paragraph “that” → “than”
g. Pg. 79 “elative” → “relative”
h. Pg. 82 last paragraph “that the each” → “that each”

Brattle Responses and Clarifications: *Addressed in edits in the report.*

Office of Regulatory Staff (ORS)

Dawn M. Hipp, Chief Operating Officer, Office of Regulatory Staff

References to ORS

The draft Report incorrectly refers to ORS as a “regulator” and providing “regulatory oversight” similar to the PSC. The draft Report’s references do not properly reflect ORS’s mission to represent the public interest before the Public Service Commission. The public interest is defined as:

The concerns of the using and consuming public with respect to public utility services, regardless of the class of customer, and preservation of continued investment in and maintenance of utility facilities so as to provide reliable and high-quality utility services.

1. ORS requests that any references to ORS as a regulator similar to the PSC be removed from the final Report. Based on the ORS review, the references are found on the following pages of the draft Report:
   - Page 1: Strike reference to ORS
   - Page 12: Strike reference to ORS
   - Pages 22-23: Strike references to ORS and footnote 17 in its entirety.
   - Page 25: Strike reference to ORS

- Pages 97 and 98: Strike references to ORS
- Page 119: Strike reference to ORS
- Page 123: Strike reference to ORS
- Page 143: Strike reference to the Office of Regulatory Staff (ORS)

Brattle Responses and Clarifications: *Addressed in edits to the report*

2. RTO Disadvantages: would SC end-use customers receive net-benefits or provide net-payments to an RTO?

Brattle Responses and Clarifications: *Our analysis indicates that South Carolina customers would receive net benefits from being in an RTO.*

3. SEEM: on pages 35-37, the references to SEEM's disadvantages should be removed from the Overview and reflected in the Disadvantages.

Brattle Responses and Clarifications: *Edited draft to reflect this comment.*

4. EIM to RTO Transition: are the sunk costs for participation in an EIM reflected in the RTO cost analysis?

Brattle Responses and Clarifications: *Our cost estimates for administrative costs are discrete for each wholesale market reform option, meaning that cost estimates for an EIM and likewise cost estimates for an RTO are expressed for that option alone based on experience elsewhere. We did not explicitly model the costs that could be incurred from a transition from one wholesale option to another, but note that costs are often incurred incrementally without being sunk. Many of the costs incurred to join or set up an EIM (e.g., investments in upgraded metering and communication systems) would be incurred by setting up and joining an RTO as well, so those investments would continue to be useful and not be sunk if transitioning from an EIM to an RTO*

Santee Cooper

Marty Watson, Chief Power Supply Officer, Santee Cooper

Please find below our first round of questions concerning the Draft Report:

General

1. The report is critical of the SEEM market for not delivering on any trades during Winter Storm Elliott when some members could not serve their load. However, it neglects to mention that no energy was available at any price, to include emergency reserves, and transmission was severely constrained from the south and west. There was firm and non-firm energy cut out of PJM at this same time. Therefore, the comment about trades in SEEM appear to be irrelevant for the document in this sense.

Brattle Responses and Clarifications: *Edited language in the report. We note that power continued to flow internally to PJM during Winter Storm Elliott.*

2. The statement in Section B on page 34 mischaracterizes the status quo, at least for Santee Cooper: "For these utilities, wholesale trades with other utilities or entities represent an important but small part of operations and resource planning."
   - Market energy and capacity purchases are a significant part of our resource mix and affects our daily dispatch decisions.
   - The section also includes the statement, "When demand for electricity rises, each utility dispatches their own generators to increase output in response, ensuring that supply and demand match." While that statement is true in the strictest sense minute-by-minute, it ignores how the hourly market is used to follow the daily load trend and "buy off" more expensive native generation.

Brattle Responses and Clarifications: *Edited language in report*

3. Are there "must run" resources in the model for transmission reliability and stability? If so, what are they and at what load levels are they dispatched?

Brattle Responses and Clarifications: *There are some must run resources in the status quo, JDA, and EIM cases to calibrate unit operation with historical operation. In the RTO cases, we allow* *for economic commitment decisions, which is consistent with RTO operations. Given the use of confidential data in the model, we cannot specify which resources and at what load levels.*

4. How are the effects of FERC order 881 considered when calculating transmission constraints in the 2030 timeframe? ‘

Brattle Responses and Clarifications: *We have not done an analysis of the impact of FERC Order 881, however this would be captured by the analysis to the extent that the South Carolina utilities have already accounted for these changes in their most recent IRPs and the data they have provided to us for inclusion into our model.*

RTO/Market

5. Can Brattle provide the individual participant inputs and results from both their benchmark study and 2030 studies? Specifically it would be interesting to know how the generating units meet the load and the associated costs of those units.

Brattle Responses and Clarifications: *Given the use of confidential data in the model, we cannot provide hourly results as part of the production for the final report.*

6. Can Brattle provide ancillary service MW estimates as opposed to the percentages included in C-19 in order for the participants to better be able to verify the inputs?

Brattle Responses and Clarifications: *The ancillary service amounts are presented as a percentage of peak load, and peak load numbers are provided in Appendix C. Therefore, MW amounts can be determined based on the numbers in Appendix C.*

7. For the benchmark studies, it appears from the slides in the appendix that the modeled costs for Santee Cooper and Duke are generally higher than their lambdas while PJM estimates are closer. Wouldn’t this variance introduce some margin of error in the results? Also, how closely do the results for Dominion come back to their actual lambdas?

Brattle Responses and Clarifications: *The results in Appendix C are from the 12/19 Advisory Board Meeting. Since that time we have updated the model with several improvements to better reflect system conditions. See response to Duke comment #6 and Appendix C.*

8. Santee Cooper importing more than what it has historically in the 2020 benchmark is odd since we traditionally have attempted to maximize our market benefit. It would appear some restriction – ether in transmission or generation – is not captured correctly.

Brattle Responses and Clarifications: *All transmission constraints that we have been given by the utilities are incorporated in the model, both for fuel usage constraints and trading volume constraints*.

9. The 2030 status quo cost estimates vary from our internal cost estimates. Having the specific inputs used for the timeframe as well as analyzing the results of specific generation, purchase and sales outputs would assist in determining why the costs vary.

Brattle Responses and Clarifications: *See response to Santee Cooper comment #5.*

10. Because the model is hourly, does Brattle believe that the benefits of SEEM are adequately captured in the 2030 status quo case? Would a sub-hourly dispatch better capture results for solar, wind, SEEM and RTO's?

Brattle Responses and Clarifications: *Since the model is hourly, the benefits associated with regional trade would be understated not only for the Status Quo but for all of the scenarios. It is likely the RTO scenarios are being understated more than the benefits from SEEM, an EIM, or JDA.*

11. The estimated investment savings from joining an RTO is driven in large part by a stated reduction in planning reserve requirements. Given what occurred during Winter Storm Elliot as well as the trend to larger regional storms that put pressure across large swaths of geography, it could be argued that a higher reserve margin for the participants is actually necessary. How much would the investment savings category be if the reserve margin benefit is not included? For example on Table 12, there is a load reduction related to the load diversity analysis, but there is also a planning reserve margin reduction. What would the saving be if the planning reserve margin stayed the same, but it was applied against the lower peak load.

- Does the statement on page 38 hold true “Requires more generators or other resources to meet the same level of reliability compared to pooled regional resource adequacy scenarios…” in light of the recent performance of RTO markets and the rumblings of increased reserve margins in some of these markets? This is a tone throughout the document and want to test the claim of increased reliability.

Brattle Responses and Clarifications: *It is not an apples-to-apples comparison to leave the planning reserve margin the same in an RTO setting as in the status quo. If the claim is that larger reserve margins are needed due to increased extreme weather events, then reserve margins would be increased in both the RTO case and the status quo. The peak load diversity across utilities in a larger regional footprint would allow for a lower planning reserve margin than in the status quo to meet the same level of reliability. See response to Lockhart Power comment #4 and Dominion comment #11.*

12. To clarify some of the results, per figure 13 PJM energy pricing is generally higher than the other associated options including the status quo. The report seems to indicate that the benefit from joining PJM would flow from selling into the PJM market. Is this a correct interpretation of the results?

Brattle Responses and Clarifications: *The operational benefits experienced by South Carolina customers in the PJM RTO case come from both purchases and sales with the larger RTO market, depending on what generation is cheapest in the market. However, on average we find that the three South Carolina utilities increase production when moving from the status quo to the PJM RTO, implying an increase in net off system sales, which explains why prices are slightly higher in the PJM RTO case than the status quo.*

13. Participation in an EIM or RTO could impose additional governance measures that lie counter to the state’s interests. The report mentions as a disadvantage that compromises may have to be made to achieve consensus with other states. What concessions have other states had to make in order to have their utilities participate? Would ESG mandates be an example?

Brattle Responses and Clarifications: *The reference to consensus refers to market rules in the RTO and other functions related to the wholesale market. Any energy policy, including ESG mandates for utilities, remain the purview of state governments.*

14. Is there an estimate to how much savings would be reduced should neighboring states not join an RTO? For example if North Carolina does not join into PJM, how much would that reduce the potential benefit given that additional wheeling costs would be incurred?

- Regarding the contract path option to join PJM without the cooperation of North Carolina: Was there any study done as to the reliability of these paths? How often have these proposed paths been curtailed for TLR's? Would such a long term arrangement require a system impact study for affected entities in North Carolina.

Brattle Responses and Clarifications: *As addressed live at the March 14th Advisory Board meeting, we did not assess the impact of North Carolina not joining PJM, others states not joining an RTO, or the reliability of a contract path option to join PJM.*

15. Per table 8, the highest potential production cost saving benefits from other studies for joining an RTO was 9%, but it generally skewed lower. The Brattle study shows closer to an 11% cost reduction for joining PJM, and an estimate closer to 3% for SERTO. Why is their substantially more benefit from joining PJM than what is seen in other similar studies?

Brattle Responses and Clarifications: *The 9% in Table 8 refers only to the production cost savings from forming an RTO, which is only comparable to a portion of the benefits estimated in our analysis (see column "Operational Savings" in Table ES-1). The production cost savings portion of benefits estimated in the report is actually smaller than the 3%-9% from experience elsewhere shown in Table 8, indicating the conservative nature of our benefit estimate.*

16. Did Brattle include any generation or transmission maintenance and forced outages in their modeling? Forced outages are briefly mentioned on page C-7, but a description of what outages are utilized may be helpful. Particularly in regards to those transmission outages that impact the ability to coordinate with PJM.

Brattle Responses and Clarifications: *Yes. Generation forced outages were modeled based on outage rates provided by the South Carolina utilities. Maintenance outages for generation resources were modeled based on publically available data from NERC. There are no transmission outages represented in the model, which results in a somewhat conservative estimate of market participation benefits. Participation in a larger regional market would help* *alleviate the impact of transmission outages, and provide larger operational benefits than estimated in this study.*

Resource Planning

17. Having a statewide IRP could introduce significant complexity to a process that is already fairly complex. What kind of streamlining methods could be implemented to the process to help enable this recommendation? California, New York and Ontario are all listed as examples of centralized IRP planning. Have any of those jurisdictions enabled a streamlined process? It would seem additional staff at the regulatory and utility levels would be necessary.

Brattle Responses and Clarifications: *We have not studied streamlined processes introduced in other states but have listed relevant case studies that have centralized planning. Under recommendations in the report, the PSC would continue to regulate and approve the IRP process and would be able to implement any procedures to make the process less complex (though such simplifications to process may in same cases reduce the ability to achieve more coordination and engagement among utilities and stakeholders). Whether the statewide IRP processes would require more staffing within utilities or within state agencies depends on the nature of the process selected. For example, the Ontario process consolidates planning activities within a government agency, shifting staffing needs from the prior separate utility models into the government agency. By comparison, California's state-wide process has a substantial role for state agency staff and its consultants, but also incorporates substantial individual planning activities for each separate utility.*

18. Would securitization changes require changes in the law?

Brattle Responses and Clarifications: *It seems revisions to existing law would be necessary, but we are not lawyers or legal experts and are not providing analysis or interpretation of existing law.*

19. How do the costs and benefits of a statewide IRP get allocated through to the customers? One particular example is if the IRP sees a benefit occurring for one system and the state from a build in another system.

Brattle Responses and Clarifications: *This would be determined by the PSC, for example in an approach that considers factors of cost causation and equity to maximize total state-wide benefits while ensuring that beneficiaries of any planning outcome will also be allocated any associated costs.*

20. Have not RTO's struggled historically to encourage new and diverse capacity to be added to their systems?

Brattle Responses and Clarifications: *We have not seen evidence to suggest this is true. RTOs historically have been very successful at attracting and integrating diverse resources including renewable energy, demand response, and DERs; this is true both in RTOs where competitive investments are a majority of supply and where utility planning drives the majority of new investment.*

21. For an expanded competitive solicitation process, are the costs of hiring an independent evaluator included in the analysis?

Brattle Responses and Clarifications: *We discuss the potential need for an independent evaluator under the disadvantages of expanded competitive solicitation. We did not quantify any costs or benefits related to this reform option.*

22. What modeling was undertaken to quantify the resource planning recommendations?

Brattle Responses and Clarifications: *We did not model the recommended changes to resource planning. The recommendation is based on the benefits experienced in other jurisdictions that have introduced similar reforms.*

Retail Changes

23. Would not the removal of any one customer class from the current billing determinants used to make rates generally cause the costs for the other classes to increase?

Brattle Responses and Clarifications: *No. If a specific customer or customer group is eligible to select an alternative energy provider, they would continue to share in remunerating utilities for* *any historical investments over a transition period. See discussion of exit fees in Sections IV.D and IV.E of the report.*

24. How would issues like those experienced in ERCOT with high customer billing after a significant weather event be avoided?

Brattle Responses and Clarifications: *As stated in previous Study Committee and Advisory Board Meetings, we are not recommending that South Carolina adopt the market structure used in Texas. Texas has retail choice for most customers in the market, including residential customers. In addition, Texas has very limited transmission interconnection with neighboring regions and an "energy-only" market structure (i.e. does not conform to the 1-in-10 reliability standard), which causes high energy price volatility and lower reliability. We do not recommend that South Carolina should consider the Texas market design and retail model.*

25. What modeling was undertaken to quantify the retail change recommendations?

Brattle Responses and Clarifications: *As addressed live at the March 14, 2023 Advisory Board meeting, our recommendations/analysis in the Retail section were qualitative not quantitative.*

SC Appleseed

Sue Berkowitz, Director, SC Appleseed

Thank you for the opportunity to participate as a member of the South Carolina Advisory committee on Utility Market Reform. SC Appleseed Legal Justice Center is a nonprofit law office that works for and with the low income community on issues that impact the lives of low income households in South Carolina. Many are on fixed income or low wage jobs and earn far less than the official federal poverty level. Access to affordable utilities for heat, air conditioning and electricity is easily out of reach and the luxury of accessing renewable sources is never attainable.

The cost of housing, including the costs of utilities, is clearly an important issue that impacts the constituency we work with. Kaiser Family Foundation reports more than 1.6 million or 32.8% of our state's residents fall at or below 200% of the federal poverty guidelines. For a family of three, this means covering food, housing, transportation, clothing, healthcare, education, and daily living on less than $44,900 a year if they are fortunate enough to be at 200%, which many of these 1.6 million do not. Therefore, my comments will be limited to the portion of your report that addresses Retail Market Reforms.

We have seen in multiple industries when there is deregulation or "consumer choice", retail users (consumers) often pay more and find themselves entering contracts or subject to practices that often cause them to pay more for the very services the market reforms promised would provide savings. This is often due to the behaviors of the providers. Even Adam Smith, the founder of free market economics, that a proper role of government is to protect consumers from producers. The efficient operation of free markets requires equal bargaining power and equal information. An article published March 2021 by the Wall Street Journal by Scott Patterson and Tom McGinty reported that U.S. consumers who signed up with retail energy companies that emerged from deregulation paid $19.2 billion more than they would have if they'd stuck with incumbent utilities from 2010 through 2019. While competitive pricing was beneficial to large industrial users, it had the opposite effect for retail consumers. They further went on to report, consumers are not experts at reading fine print or understanding the nuances of contracts to ensure that they receive the benefits that they are promised. This can result in even worse outcomes for our state's seniors and minority communities that are often targeted by retail sellers who are counting on their unequal bargaining power to entice them into contracts that rarely if never fulfill want is promised.

The offering of customer choice cannot translate into customer benefit when we do not also include consumer protections that can provide guardrails to prevent these problems. This report contains a cost analysis for Brattle's recommendations. What it does not include is a cost/benefit analysis which is needed to fully vet whether this should be the path forward for South Carolina and if this will be in the b t of its 5.1 million consumers who will all be impacted as purchasers in the retail market alysis has not been done at this time.

With South Carolina utilities recently initiating SEEM November 1, 2022 it is important that we test this first venture into regional work and we would recommend that our state monitor and analyze both the successes and challenges of this regional system where we would have more representation and impact in decision making. We do not support further moves to PJM, where those who have little voice, SC consumers, will have none.

Brattle Responses and Clarifications: *We are not recommending South Carolina pursue retail choice for residential customers at this time. Furthermore, we agree that if the state chooses to offer retail choice for large customers the PSC must assign properly designed exit fees and other* *safeguards to eliminate cost-shifting between customers. See discussion in Sections IV.D and IV.E of the report. Please note that membership in an RTO does not imply retail choice for any customer, large or small. Membership in an RTO and retail choice are separate reform options that can be pursued independently.*