Assessment of Potential Market Reforms for South Carolina's Electricity Sector

FINAL REPORT TO THE ELECTRICITY MARKET REFORM MEASURES STUDY COMMITTEE OF THE SOUTH CAROLINA GENERAL ASSEMBLY

PREPARED BY

John H. Tsoukalis
Kathleen Spees
Johannes P. Pfeifenberger
Andrew Levitt
Andrew W. Thompson
Oleksandr Kuzura
Evan Bennett
Son Phan
Megan Diehl
Ellery Curtis
Sylvia Tang
Ryan Nelson

PREPARED FOR

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Brattle

NOTICE

This study has been funded by the South Carolina State General Assembly under the Electricity Market Reform Measures Study Committee and has been informed by data and input provided through a thirteen-month process. Throughout the course of this study, Brattle consultants conducted several engagement sessions with the Study Committee composed of members of the South Carolina Senate and House as well as the Advisory Board comprised of a wide range of stakeholders in South Carolina's energy industry. For a complete timeline of events and list of Study Committee and Advisory Board members and their affiliations, see Appendix D.

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Executive Summary

In accordance with the requirements of Act 187, the South Carolina Electricity Market Reform Measures Study Committee ("Study Committee") has commissioned this independent assessment to examine the potential benefits of introducing market reforms to South Carolina's electricity sector. Over a period of thirteen months beginning March 2022, we have worked in close coordination with the Study Committee and the Advisory Board of stakeholder representatives to assess the status of South Carolina's electricity sector, answer questions posed by state legislators, refine the study scope, and develop primary study assumptions with input from the Advisory Board. We present in this report our independent findings with respect to the benefits of introducing various market reforms to South Carolina's electricity sector.

At present, South Carolina's electricity sector is structured under a vertically integrated utility model, with approximately 61% of all energy demand served by three large investor-owned utilities: Duke Energy Progress and Duke Energy Carolinas (collectively "Duke"), and Dominion Energy South Carolina ("Dominion").[1] Each of these utilities is granted the exclusive right to provide electricity supply to retail customers within their service territories, subject to regulatory oversight from the South Carolina Public Service Commission (PSC). The remaining 39% of South Carolina energy demand is served by the large state-owned utility South Carolina Public Service Authority ("Santee Cooper"), 20 member-owned electric cooperative utilities, and 7 municipally owned utilities.[2]

[1] These utilities serve 7% (Duke Progress), 26% (Duke Energy Carolinas), and 27% (Dominion) of South Carolina energy demand. In addition to their role as vertically integrated utilities and distribution providers, these entities (and the state-owned utility Santee Cooper) also act as the Balancing Authorities that manage real-time energy balance on the system within their bulk transmission system areas, and provide energy supply to municipal and cooperative utilities. In their roles as Balancing Authorities, these same companies support energy deliveries to 8% (Duke Progress), 34% (Duke Energy Carolinas), 28% (Dominion), and 30% (Santee Cooper) of South Carolina's customers. For the purposes of this study, we will discuss the role of these entities both as Balancing Authorities (collectively, the four companies serve all South Carolina customers in this role) and as vertically integrated utilities (31 separate utility companies serve South Carolina customers in this latter role, under a range of ownership structures and business models). Compiled from Energy Information Administration (EIA), Annual Electric Power Industry Report, Form EIA-861, detailed data files, reflects year 2021 data.

[2] Santee Cooper directly serves 12% of South Carolina customers, and indirectly serves the majority of energy supply needs to South Carolina's cooperative utilities through a supply contract with Central Electric Power Cooperative (a company that is in turn owned by 20 member cooperatives that act as the distribution utilities serving end use customers and 23% of South Carolina's total energy demand). Municipal utilities serve the

In this study, we examine the nature and size of potential benefits that could be achieved by market reforms in the electricity sector. We structure our assessment of the potential benefits across three areas of reform:

- **Wholesale market reforms** that could improve the cost-effectiveness of generation resource operations and trade across regions;
- **Resource planning and competitive investment reforms** that seek to improve the cost-effectiveness of resource investment decisions, some of which can also shift investment risks from customers to generator owners; and
- **Retail market reforms** that would offer customers greater opportunities to select their preferred resource mix or rate structure, including possibly from multiple competitive retail suppliers.

We find that South Carolina ratepayers stand to gain substantial benefits from a measured introduction of enhanced regional coordination and market reforms in all three of the above categories. These benefits can be achieved most reliably through incremental reforms that follow best practice in the sequencing and introduction of various reforms. Doing so will maximize consumer benefits and manage transition risks considering South Carolina's unique circumstances and industry structure.

remaining 4% of South Carolina's energy customers. Compiled from Energy Information Administration (EIA), Annual Electric Power Industry Report, Form EIA-861, detailed data files, for year 2021 and Central Electric Power Cooperative, Inc., Integrated Resource Plan 2021–2040, 2020.

WHOLESALE MARKET REFORMS

Today, South Carolina's utilities are responsible for scheduling generation within their service territories. These utilities forecast their electricity demand, determine what generating facilities to turn on or off on a daily, hourly, and sub-hourly basis, schedule power deliveries to customers, and engage in bilateral purchases and sales with neighboring utilities. The large utilities are additionally transmission operators and owners, and so must allow third parties to schedule power deliveries across their respective transmission systems under federal transmission "open access" laws. To support more cost-effective bilateral trades in the short-term spot market, the South Carolina utilities, along with other utilities in the Southeast, have introduced a new Southeast Energy Exchange Market (SEEM) that began operations on November 9, 2022 and facilitates non-firm bilateral transactions in 15-minute intervals.

To examine the potential benefits and costs of market reforms to the South Carolina utilities' wholesale market and transmission system operations, we have conducted a detailed assessment of several alternative wholesale market structures that are in use throughout the U.S. In order of increasing levels of wholesale market competition and expanded geographic scope, the wholesale market reform options we examined are:

- Retain the **Status Quo** with South and North Carolina (Carolinas) utilities operating generators to match their own customers' demand while trading power bilaterally including through the new SEEM;
- Implement a Carolinas-wide **Joint Dispatch Agreement (JDA)** under which the Carolinas utilities would make arrangements to jointly coordinate and improve the dispatch efficiency of their generation (similar to the JDA Duke is currently using in its South Carolina and North Carolina service territories to increase dispatch efficiency across its two subsidiaries);

- Implement a **Southeast Energy Imbalance Market (EIM)** in which an independent third party fully optimizes the real-time dispatch of resources in the Carolinas and across the Southeast, a structure that is currently used in eleven states across the Western U.S. The EIM option can be supplemented with a regional resource adequacy framework;[3]
- Create a **Southeast Regional Transmission Organization (RTO)** with the same footprint as the hypothetical Southeast EIM above, but with additional functionality that includes day-ahead market operations, consolidated balancing areas with pooled reserves, a regional resource adequacy framework, and regional transmission service and planning; and
- Join or otherwise integrate with **PJM Interconnection (PJM) RTO**. This option offers the same functionality as the Southeast RTO, but with the Carolinas joining PJM (or otherwise integrating with PJM's wholesale power markets),[4] the existing neighboring RTO that presently covers utility areas across thirteen states and the District of Columbia (covering the Mid-Atlantic states from the northern portion of North Carolina to New Jersey and stretching west to Chicago).

[3] The new FERC-approved Western Resource Adequacy Program (WRAP) allows utility participants to take advantage of regional load diversity and the trading of well-defined capacity products. WRAP participation can be combined with participation in the CAISO-administered Western Energy Imbalance Market (WEIM), the SPP-administered Western Energy Imbalance Service (WEIS), and the SPP-administered "Markets+" and Western RTO options. See M. McNichol, "WPP Announces FERC Approval of WRAP Tariff," Western Power Pool, February 10, 2023; Western Power Pool, WRAP: Western Resource Adequacy Program, accessed February 1, 2023; and Southwest Power Pool, Western Energy Services, Markets + Webinar, November 17, 2021.

[4] In addition to fully joining PJM as a member, PJM may be able to accommodate wholesale market participation of South Carolina utilities in a non-RTO pooling arrangement, similar to the regional energy and resource adequacy market option offered by CAISO and SPP in the Western U.S.—such as EIM, EDAM, "Markets+" and "WRAP"—as discussed in more detail in the body of this report. Joining or otherwise integrating with PJM's wholesale power markets would not change the vertically-integrated and state-jurisdictional nature of South Carolina's utilities.

Table ES-1 summarizes the net benefits that we estimate would accrue to South Carolina customers under each of these wholesale market reforms, ranging from $1 million to $362 million per year. The benefits to South Carolina customers include cost savings accruing to customers in the Santee Cooper and Dominion balancing areas, plus a share of the cost savings accruing to customers in Duke's balancing areas based on the portion of load in Duke's BA located in South Carolina. These annual benefits accrue through operational and investment-cost savings, which likely will increase over time as load grows, fuel prices increase, and the generation mix changes over the years to include more renewable resources.

Operational savings arise both by allowing power to flow more freely across multiple utility areas in the larger geographic region (without having to book transmission at each utility boundary) and from the improved efficiency from coordinating day-ahead scheduling and real-time dispatch across greater geographic areas.

Investment cost savings in the RTO scenarios or in a coordinated resource adequacy framework over the same regions, arise from the ability to reduce the total amount of necessary generation investments due to the higher diversity of supply and demand in the greater geographic area in a regional RTO market.[5] Administrative costs arise from operation and implementation of the business processes that perform the coordinating functions.

TABLE ES-1: ANNUAL SOUTH CAROLINA CUSTOMER SAVINGS FROM WHOLESALE MARKET REFORMS (2022$ MILLIONS/YEAR, 2030 STUDY YEAR)

	Units	Operational Savings	Investment Cost Savings	Administrative Costs	Annual Net Benefits
Carolinas JDA	$ Mln/year	$10-$13	N/A[6]	$2 – $4	**$6-$11**
Southeast EIM	$ Mln/year	$22-$27	N/A[6]	$2 – $5	**$17-$25**
Southeast RTO	$ Mln/year	$87-$106	$94–$117	$36 – $66	**$115-$187**
Integrate w/ PJM	$ Mln/year	$163-$200	$158–$198	$36 – $40	**$281-$362**

Sources/Notes: Savings are those that South Carolina customers would accrue including reductions to operating costs (i.e., fuel costs, variable costs, cost of purchases, net of sales revenues), and reductions to investment costs (i.e., reductions to total capacity requirements due to load diversity). Values reported in 2022$.

5 This table does not account for the additional benefits that could be achieved if RTO participation is also used as a means to gain access to lower-cost capacity through competitive generation procurement or regional trade of capacity; those potential benefits are discussed in Table ES-3, Section III.E, and Appendix B.

6 Capacity investment benefits similar to those from RTO participation could also be enabled through the creation of a region-wide resource adequacy framework, such as the new Western Resource Adequacy Program (WRAP), as noted earlier.

The quantified operational savings are comparable to the results of similar studies in other parts of the country, where retrospective studies of RTO market benefits show operational savings in the 4%–8% range, with a portion of these savings achievable through a regional EIM (noting that a portion of regional coordination benefits are already accounted for in the status quo scenario through SEEM).[7] Our estimates of generation investment cost savings created through RTO participation (or alternative regional resource adequacy frameworks) are consistent with the experience of other states, such as in Louisiana, where Entergy was able to reduce its planning reserve margin from 18% to 12% due to regional load diversity by joining the Midcontinent ISO (MISO).[8] Entergy estimated that joining MISO would save the utility between $170 million and $225 million in power production costs and would save customers more than $1 billion for the 2013 to 2022 timeframe.

Our estimates of operational savings may be conservatively low due to various modeling assumptions and simplifications. Based on experience to date in other regions and due to the conservative nature of our estimates, we anticipate that the scale of economic and reliability benefits from participation in regional wholesale electricity markets will grow as the sector evolves to incorporate a growing share of variable renewable resources, demand response, batteries, and distributed resources.

In addition to the economic savings South Carolina customers would accrue, enhanced participation in regional wholesale power markets can offer other benefits, including increased volume of competitive energy transactions (i.e., higher liquidity) and transparency of market prices, a more diverse resource mix, enhanced support for bilateral contracting, and efficiencies unlocked by region-wide transmission planning. Immediately upon joining an RTO, South Carolina's cooperative member-owned and municipally owned utilities would enjoy greater

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7 The Brattle Group, Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California, prepared for California ISO (CAISO), July 8, 2016; J. Tsoukalis, et al., Western Energy Imbalance Service and SPP Western RTO Participation Benefits, The Brattle Group, December 2, 2020.; J. Chang, *et al.*, Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint, The Brattle Group, December 1, 2016.; J. Chang, *et al.*, Joint Dispatch Agreement Energy Imbalance Market Participation Benefits Study, The Brattle Group, January 14, 2020.

8 Entergy, which owns approximately 24,000 MW of generation, anticipated that its generation capacity requirement would be 1,400 MW less (approximately 6% of peak load) as a MISO member than as a standalone entity, since its effective reserve margin would be 12% as a MISO member compared to 17%–20% as a standalone entity. MISO's subsequent analysis found that the MISO South region, which then included Entergy, achieved $560–$750 million in load diversity benefits. See Entergy, An Evaluation of the Alternative Transmission Arrangements Available to the Entergy Operating Companies and Support for Proposal to Join MISO, presented before the Public Utility Commission of Texas, May 12, 2011; and MISO, 2015 Value Proposition Stakeholder Review Meeting, January 21, 2016.

market transparency and access to many sources of alternative generation supply and contractual counterparties through which to secure future power needs. For a similar reason, an RTO market structure enhances the potential benefits achievable from introducing partial or full retail choice. Under the EIM and in the two RTO options we modeled and evaluated, transactions, generation dispatch, and other wholesale functions are run by a third party that is independent from any individual market participants or industry sector. This independent market operator is answerable to a broad body of members so that no single market participant or sector controls the entity's operations or governance. Trade can therefore proceed on a level playing field, allowing all market participants equal access to the benefits of wholesale power markets. None of these wholesale market reforms would change the state's jurisdiction and authority to oversee integrated planning, resource investments, or retail rates of investor-owned utilities.[9]

If South Carolina transitions toward a JDA or regional wholesale market model, implementation timing and complexity will be an important consideration for maximizing long-term benefits and minimizing transition risks. For both the JDA and to a lesser extent a new Southeast EIM, there is a risk that the more incremental initial steps could delay the timeframe for full RTO participation, thus delaying realization of greater consumer benefits. Creating a new Southeast EIM, regional resource adequacy market, or RTO could similarly be time-intensive efforts that are dependent on coordination with entities beyond South Carolina's direct control. It may be possible to compress implementation timeframes if other states and utilities in the Southeast were willing to undertake this step and the new Southeastern market structure were implemented with support from one of the existing U.S. ISO/RTO organizations.[10]

Joining an existing neighboring RTO (i.e., PJM) is the most expeditious path to full RTO membership. PJM has extensive and recent experience integrating new utility balancing areas, with integration of new members taking as little as 18 months. Under this model, South Carolina would operate within all existing RTO market and governance structures, including the option to retain its vertically-integrated and state-jurisdictional utility structure.

Another pathway that South Carolina could consider would be to integrate with PJM wholesale markets, but under an alternative membership and governance model that is tailored to the unique requirements of South Carolina and other Southeastern states. Examples of similar

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[9] Electric cooperative and municipal utilities operate under a different regulatory model, in which the state's authority to regulate retail rates is limited. This would not change under any of the wholesale market reforms discussed in this report.

[10] For example, when Colorado and Wyoming utilities considered forming a new "Mountain West" RTO, they received proposals from SPP, CAISO, MISO, and PJM to design and create the contemplated RTO within just a few years. Mountain West Transmission Group, Frequently Asked Questions, updated January 5, 2017.

arrangements include the Western EIM and Extended Day-Ahead Market (EDAM), the Markets+ option offered by Southwest Power Pool (SPP), and the Western Power Pool (WPP) Western Resource Adequacy Program (WRAP). In each of these cases, the participating states, public power entities, and utilities wished to achieve the economic and reliability benefits of pooling resources within a broad regional marketplace; but wanted to do so under a new governance structure that suited the specific state policy and regulatory models of those regions. The economic benefits achievable under such a pathway are identical to those described under the Southeastern RTO and PJM options described in Table ES-1 above, but would require more extensive coordination across states and utility areas over a longer timeframe to achieve consensus and develop the governance and membership models.

Related to the EIM, Southeast RTO, and PJM RTO membership and integration options, the greatest benefits will be realized if the South Carolina utilities are joined by other utilities with neighboring service areas to achieve a larger scope of regional coordination of the energy market and resource adequacy framework across a more diverse footprint. This suggests that policymakers and utilities in South Carolina should join with other states and utilities to coordinate in the decision-making process toward joining or creating a regional RTO or EIM and resource adequacy framework, even if entry dates are uncertain.

Based on these findings regarding wholesale market reforms, we recommend that South Carolina consider immediately initiating processes to join, create, or integrate with a regional RTO marketplace. We recommend to:

- **Establish a policy and timeframe for integrating with an RTO**, considering at least three alternative pathways for full RTO integration:
  - *Join an existing RTO* (i.e., PJM) under the existing governance and membership model (South Carolina would maintain all authorities over vertically integrated utility planning and ratemaking, but would not be in a position to dictate any changes to the existing RTO governance structure); **or**
  - *Create a new Southeast RTO,* provided that neighboring states and utilities show interest in initiating the multi-state effort to create a new RTO; **or**
  - *Integrate with an existing RTO but under a new governance model,* such that energy and resource adequacy benefits can be achieved, but under a governance structure that is suited to the prevailing state regulatory model in South Carolina and other states in the Southeast (e.g. possibly modeled after the Western EIM and EDAM, SPP's Markets+, and WPP's WRAP).
- **Seek coordination with other states and utilities across the Southeast,** particularly North Carolina, toward a regional markets pathway that maximizes the geographic footprint and coordinated use of regional transmission infrastructure; and
- **Authorize the PSC to review and approve each utility's regional integration plan** subject to defined criteria and timelines. [11]

RESOURCE PLANNING AND COMPETITIVE INVESTMENT REFORMS

The second category of potential reforms relates to how long-term resource investment, resource retirement, and supply contracting decisions are made. Current practice in South Carolina relies on Integrated Resource Plans (IRPs) conducted by the utilities individually for each of their service territories, which are subject to PSC oversight and consider interveners' comments. An IRP accounts for the utility's projected demand and resource needs, planned

[11] As two examples of legislation in other states, Colorado Senate Bill 21-072 and Nevada Senate Bill 448 establish relevant authorities, timelines, and evaluation criteria for regional market integration. Both states offer relevant experience for South Carolina given their similar, vertically integrated utility models and reliance on integrated resource planning under state regulatory oversight. See General Assembly of the State of Colorado, Colorado Senate Bill 21-072, 2021 Regular Session, signed June 24, 2021; Nevada Legislature, Nevada Senate Bill 448, 81st Session, signed June 10, 2021.

resource retirements and supply contract expirations, new generation investments, demand-side programs, and procurements proposed to meet projected future resource needs. Once the PSC approves a utility's supply plans within the IRP or follow-on processes, including approval through the Certificate of Public Convenience and Necessity (CPCN) process, 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.[12] Going forward, an increasing portion of supply needs could be procured via competitive solicitation processes from third-party Independent Power Producers (IPPs), depending on the outcomes of several active regulatory dockets and ongoing solicitation processes.[13]

There are several options for introducing enhanced planning and competition into South Carolina's resource investment decisions, ranging from incremental to more foundational changes. The resource planning and competitive investment reform options we examined are:

- **Introducing a statewide IRP across all South Carolina utilities**, the goal of which would be to achieve efficiencies by considering all supply needs on a statewide basis with an enhanced role of state agencies to directly oversee the state IRP process or to coordinate among separate utility IRPs. The statewide identified needs could then be developed under utility self-supply or procured via statewide or utility-specific competitive solicitations;
- **Expanding the role of competitive solicitations in utility IRPs**, that seek to meet IRP-defined resource requirements from among competitively-bid projects that can be proposed by the incumbent utility, neighboring utilities, third-party IPPs, demand response aggregators, or other developers. All-source solicitations offer the additional benefit of supporting competition across alternative technologies as well as across alternative providers. South Carolina is in early stages of experience with such competitive solicitations, whose role can be expanded in the future;
- **Transitioning to partial or full reliance on competitive supply investments**, in which a regional resource adequacy mechanism or capacity market would be used to attract a portion or all of future supply investment needs. Such a structure maximizes competitive pressures relative to resource price (leaving states and consumers to pursue any non-price policy priorities through complementary IRP, policy programs, or contracting choices). A market-based approach to supply investments would reduce the cost, increase price transparency,

12 Electric cooperatives and municipal utilities do not earn return on investments.

13 The option (but not the requirement) to rely on competitive solicitations was introduced in the 2019 Energy Freedom Act. See South Carolina Office of Regulatory Staff (ORS), Summary of the South Carolina Energy Freedom Act, September 2019.

and shift the risk of uneconomic or stranded investments for customers (who currently pay for regulated investments, even those that prove uneconomic in retrospect) to private companies (who would not be allowed to charge customers more even if they failed to recover the cost of poor investments). The potential to protect customers from exposure to any future stranded investment costs is particularly salient in South Carolina given recent experience with the V.C. Summer nuclear plant expansion.[14]

- **Considering the option for securitization of costs related to retiring stranded thermal assets**, (i.e., those assets that are no longer cost-effective to continue operating, but whose investment costs have not yet been recovered by the utility). Once a thermal asset is considered stranded, "securitization" can reduce the costs imposed on customers and could be considered as an alternative or supplement to ongoing cost recovery, accelerated depreciation, or prudence-based disallowances.

Table ES-2 summarizes our qualitative assessment of the potential benefits and costs/risks associated with these resource planning and competitive investment reform options, including an assessment of their relevance within South Carolina's context.

[14] Though not the focus of this study, experience with the V. C. Summer nuclear plant expansion provides a vivid example of stranded asset risk. The V.C. Summer expansion construction and associated cost recoveries were approved by the Board of Directors of Santee Cooper and the South Carolina PSC under a special process enabled by the 2008 Baseload Review Act (later repealed in 2018). Though the project was never completed, approximately $9 billion in expenditures for partial construction will need to be recovered from customers over the next decades. See Post and Courier, "Santee Cooper, SCE&G pull plug on roughly $25 billion nuclear plants in South Carolina," July 31, 2017; Utility Dive, "Santee Cooper, SCANA abandon Summer nuclear plant construction," July 31, 2017; and Santee Cooper, Annual Report 2021, March 11, 2022.

TABLE ES-2: RESOURCE PLANNING AND INVESTMENT REFORMS POTENTIAL BENEFITS, RISKS AND IMPLEMENTATION CONSIDERATIONS

Option	Potential Benefits	Potential Costs and Risks	Implementation Considerations
Status Quo with Utility IRP	• PSC oversight and approval of investment choices in public interest • Ability to weigh both cost & non-cost criteria in planning (e.g., jobs, environment, equity)	• Relies on utility and PSC judgement and forecasting to select resources • Customers retain most of the risk of uneconomic investments • Limited role for IPPs with lower-cost options	• No reforms
Statewide IRP Across All South Carolina Utilities	• Coordination of analysis across greater statewide scope • Maintains PSC oversight and approval of investment choices • Can inform policymakers weighing major policy changes (e.g., environmental policy) • Reduced reliance on utility planning judgement and forecasts	• Risk of uneconomic investments mostly stays with customers • Increased reliance on state agency planning judgement and forecasts	• Requires expanded planning authorities in PSC or other state agencies • Resource investments could be utility self-supply, utility contracts with IPPs, or based on "single buyer" model w/ a state entity as contractual counterparty to IPPs
Expanding the Role of Competitive Solicitations in Utility IRPs	• Lower costs from increased competition for supply commitments across technologies and suppliers • Maintains PSC oversight and approval of investment choices • Shifts more risk from customers to producers (e.g., fixed-priced contracts) • "Market test" can affirm cost-effectiveness of utility self-supply	• Investment recovery risks stay with customers over contract duration • Utility incentives favor self-supply • Barriers to ensuring level competition between utility-proposed projects vs. IPP-proposed projects	• Need to develop and refine all-source procurement structures relative to best practices • Option to mandate solicitations to meet most or all future resource needs • PSC or other agency oversight of independent evaluator can ensure fair competition (particularly if utility self-supply projects can compete)
Transition to Partial or Full Competitive Supply Investments	• Competitive forces drive cost reductions and supplier innovation • Any risks of poor investment choices borne by private companies (stranded asset costs cannot be passed to customers)	• Transition costs and risks from fundamental changes to utility business model • Investment choices driven only by market prices (i.e., reliability at least cost); reduced consideration of non-price policy objectives	• Transition plans needed for utility-owned generation assets (e.g., incremental transition, divestiture, or functional separation) • With divestiture, transition plan needed to recover legacy investment costs
Securitization of Costs Related to Retiring Stranded Thermal Assets	• Can reduce customer costs associated with stranded asset retirements • PSC would have authority to grant securitization of retiring stranded assets	• Requires mechanism (e.g., rate surcharge) to guarantee cost recovery of securitized amounts. • Removes PSC authority to disallow cost recovery	• Can be implemented with minimal changes to existing law

The scale of the benefits that could be achieved from a more coordinated and competitive resource investment model depend on the level of competition introduced, the timeframe over which major supply investment decisions will be made, whether the competitive reforms follow best practices for achieving the relevant benefits, and whether transition risks are adequately mitigated. Table ES-3 summarizes the potential customer savings that could be achieved from competitive resource procurements under a scenario where South Carolina joins an RTO with a regional capacity market and begins participating either: (a) on a limited basis, with utilities continuing to rely on IRP-based resource development (as is the case under the status quo with limited or no use of competitive solicitations), but using the capacity market to procure incremental needs or sell surplus capacity; or (b) on a more comprehensive basis, relying on the market to attract the lowest-cost resources to satisfy all identified capacity needs.

Benefits would begin accruing immediately upon joining an RTO with a regional capacity market, but would tend to grow over time as the market is used to attract a lower-cost resource mix compared to what otherwise would have been developed under the status quo model. The higher end of this range reflects the benefits from a successful transition to competition for all resource needs (with proper risk mitigation). More modest or incremental reliance on competitive solicitations can be expected to achieve a proportion of these estimated benefits that is commensurate with the share of going-forward investments subject to competitive forces.

TABLE ES-3: POTENTIAL SAVINGS FROM COMPETITIVE SUPPLY INVESTMENTS (2022$ MILLION/YEAR)

Scenario Name	Scenario Description	Immediate Customer Savings ($mln/year)	Long-Term Customer Savings ($mln/year)
Incremental Participation	Maintain utility IRP process for bulk capacity needs but use regional capacity market for purchasing incremental needs and selling surplus	$25–$120	$150–$300
Full Participation	Graduated transition from utility IRP to competitive supply investment via capacity market for full capacity needs	$25–$120	$150–$370

Sources/Notes: Reported in nominal U.S. dollars. Savings arise from reductions to reserve margins due to supply and load diversity over a larger footprint, net capacity surpluses being sold into the market thus offsetting customer costs, the ability to right-size capacity holdings every year, and from attracting low-cost capacity resources such as demand response and uprates that may otherwise not be identified. Immediate savings are those experienced in the first few years upon joining with an RTO due to the ability to recover some capacity costs associated with any existing supply surplus above the new lower capacity requirement through market revenues. Long-term savings are those experienced later in the future after new build capacity is needed. The two scenarios are the same in the initial years because legacy investments have already been made regardless of how South Carolina decides to participate in the market in the future.

Based on our assessment of potential supply investment reform options, we recommend that South Carolina policymakers consider the following options to incrementally introduce competition over time. We note that many of these reform options are complementary to each other (not mutually exclusive alternatives).

We recommend that South Carolina:

- **Join, create, or integrate with an RTO or regional resource adequacy market that ensures resource adequacy (accounting and enforcement) over a larger, more diverse footprint**. This step would yield immediate cost savings by reducing reserve capacity requirements for South Carolina utilities, by enabling the utilities to more cost-effectively manage temporary surpluses and deficits in their resource plans, and by easing the logistics of major plant retirements. If South Carolina additionally wanted to create the option to transition to a model that is partly or fully reliant on competitive generation investments in the future, we recommend prioritizing consideration of an RTO with a track record of attracting competitive generation investments.
- **Authorize the PSC or other state agencies to consider or conduct statewide IRP processes,** if the PSC identifies a benefit to conducting such an exercise, either to achieve cross-utility coordination benefits, better inform policy choices on a statewide basis, or provide statewide needs assessments for the purpose of competitive solicitations. The option for an agency-overseen statewide IRP could be utilized either on an ad hoc basis when a specific need is identified, or could be incorporated into regularized IRP processes.
- **Incrementally introduce and expand the role of competitive solicitations within utility and/or state IRP processes**. South Carolina is presently gaining more experience with competitive renewable and all-source solicitations, which (along with experience in other states) can inform the most advantageous oversight and procurement model. Further expanding the role of competitive solicitations can be achieved via options such as: (a) requiring (rather than "allowing" as is done currently) future supply needs identified in IRPs to be met through all-source competitive solicitations; (b) designing competitive solicitations that will consider utility self-build projects alongside IPP projects, authorizing state agencies to rely on an independent evaluator to conduct the process and recommend winning projects to the PSC for approval; (c) enabling cooperative and municipally owned utilities to participate in state agency or utility-specific procurements, allowing them the option (but not the obligation) to procure a share of selected resources; and (d) (after joining an RTO) considering the option for

reliance on regional markets for providing a defined portion of IRP-identified supply needs.

- **Confirm or clarify regulatory policies related to the retirement of uneconomic aging resources** to ensure that utilities have the ability and incentive to retire aging generating assets when other lower-cost supply options become available. In determining the most beneficial outcomes for ratepayers, authorize the PSC to utilize all potentially relevant cost recovery mechanisms for prudent retirement decisions, including traditional cost recovery (beyond the planned retirement date), accelerated depreciation, and securitization.
- **Consider additional competitive investment reforms in the future.** After gaining experience with RTO market participation, competitive IRP-based procurement processes, and retail market reforms (discussed below), reassess the question of competitive investment reforms to determine whether further transition to competitive investments is desired. If so, consider utilizing a graduated transition path that would rely increasingly on competitive generation investments over time as demand increases, existing resources retire, and existing contracts expire.

RETAIL MARKET REFORMS

The third category of potential reforms relates to the retail market and focuses on the question of whether and how customers can select alternative sources or providers of retail electricity. South Carolina customers currently receive retail electricity from the utilities that have been awarded exclusive rights to serve customers within their service territories. For most customers, the PSC approves the level and structure of the electricity rates that utilities can charge to each class of customers in accordance with the cost-of-service rate regulation approved by the PSC. Customers seeking different rate structures, more access to clean energy resources, or investment in distributed resources (such as rooftop solar or battery storage) have the ability to participate in utility-offered programs where they exist, signal interest in new programs through requests to their utility, and act as interveners before the PSC when regulations for new programs or rates are being considered. Customers that remain dissatisfied with the rates, available programs, or other aspects of their utility-provided retail service are not able to seek an alternative retail electricity provider.

There are several options for introducing greater retail choice into South Carolina, ranging from incremental to more foundational changes. The retail reform options we examined are:

- **Utility retail rate reforms to offer additional customer choices**, that would authorize or require utilities to design more efficient or advanced retail rates structures, with the goal of offering customers more choices on rate structure, green power offerings, incentives to improve consumption management to reduce their bills, or opportunities to leverage distributed resources, electric vehicles, or new electric heating technologies such as smart thermostats and heat pumps. Enhanced retail rate design that follows the fundamental principle of cost-causation can lead to improvements in equity and fairness in cost recovery by removing unintended cost-shifting among customer classes and mitigate distribution cost spending by encouraging customers to use electricity more efficiently.
- Enabling **partial retail choice** for large commercial and industrial (C&I) customers, so that these customers have the ability to seek self-supply or contract with a third-party electricity supplier. Under partial retail choice, the incumbent utility would remain the provider of distribution, transmission, and metering services, but would no longer be the only company able to provide generation, or retail services. Customers would be able to negotiate their electricity rates in terms of the price, rate structure, level of hedging, preference for green resources, Demand Response (DR) and Distributed Energy Resource (DER) management, or other features. In other states, large customers have demonstrated a high level of sophistication around their consumption and tend to exercise their right to choose alternative retail energy suppliers. While not strictly necessary, the benefits of partial retail choice are greatly enhanced when paired with a regional wholesale market and most states that have enabled partial retail choice are within existing RTOs.
- Enabling **full retail choice** including residential and small business customers, can offer the same benefits of competitive retail markets and alternative suppliers to small customers (though only a subset of residential customers have tended to exercise their right to switch to an alternative retail supplier in other regions). If pursuing full retail choice, this should be done in a coordinated timeframe with a shift to competitive supply investments to ensure that customers have a meaningful variety of options for securing wholesale and retail supply. This effectively requires an RTO.
- Enabling **Community Choice Aggregation** is an option for enabling communities (even those not served by a municipally owned utility) to select a third-party supplier of retail electric service. Communities in other states have often exercised their option to seek third-party supply as a means to reduce costs, reflect environmental goals, or (usually) both. While not strictly necessary, the benefits of CCAs are greatly enhanced when paired with a regional wholesale market and most states that have enabled partial retail choice are within existing RTOs.

- **Competitive reforms to enable distributed energy resources,** are those options that focus on creating opportunities to incentivize and leverage third-party DR and DER providers to provide value to support bulk system needs (capacity, balancing) or end-use customer value (green energy, bill reduction, more efficient consumption, etc.). RTO markets offer a substantial variety of such opportunities to aggregators of DERs and DR who, according to FERC Order 2222 rules, must be enabled to compete fully in wholesale markets to serve all defined grid services as long as the DER/DR resource in question meets technical capability standards. Competitive all-source solicitations also offer opportunities to leverage new DER/DR technologies, but require a technology-neutral suite of product definitions and programs to fully enable the potential.
- Establishing a **third-party energy efficiency administrator** could create an opportunity to regularize and expand energy efficiency (EE) programs to leverage opportunities that are cost-beneficial to customers but that have not been fully developed under existing structures.

Table ES-4 summarizes the relative advantages of the range of retail reform options identified by the Study Committee and Advisory Board for detailed review in this study.

TABLE ES-4: RETAIL REFORMS POTENTIAL BENEFITS, RISKS & IMPLEMENTATION CONSIDERATIONS

Option	Potential Benefits	Potential Costs & Risks	Implementation Considerations
Status Quo with Exclusive Utility Service for Retail Supply	• Customers enjoy price stability as most investment costs are recovered over a long period • Rates and investment choices subject to state oversight	• Investment and fuel price risks borne by customers under cost-of-service regulation • Customers unable to negotiate, switch providers, or pursue self-supply if unsatisfied with service	• No reforms
Utility Retail Rate Reforms to Offer Additional Customer Choices	• Enhanced rates can offer better efficiency, green supply options, and DR/DER incentives	• Requires careful design to offer system-wide benefits and protect customers who are not able to take advantage of new options	• Some reforms already possible and the legislature can explicitly authorize/mandate others (subject to PSC oversight)
Partial Retail Choice (large C&I customers only)	• Empowers large customers and businesses to negotiate lower or differently-structured rates, self-supply with clean energy, and participate as DR/DER in RTO • Would lower costs for businesses in the state	• Need to equitably address cost recovery of utilities' legacy investment costs (either shift to customers ineligible for switching, assign exit fees, or issue transition charges to customers eligible for switching)	• Legislation required to enable partial retail choice but can be implemented without any coordination from neighboring regions
Full Retail Choice (including residential and small businesses)	• Enables all customers (large and small) to pursue their preferences for clean energy supply, innovative rate structures, or other service offerings from competitive retailers	• Regulatory and data barriers can prevent retailer innovation (may materialize as low switching rates) • Retail products can be confusing to unknowledgeable buyers of electricity, potentially exposing them to greater market volatility	• Regulated service options need to be designed for customers who do not choose competitive options • Regulatory oversight needed to implement switching rules, unbundle rates, design and assign exit fees, and ensure consumer protection
Community Choice Aggregation (CCA)	• Empowers communities to negotiate rates and contract with other suppliers (e.g., for lower rates or policy goals)	• Need to equitably address cost recovery of utilities' legacy investment costs	• Legislation required to allow CCAs to form but can be implemented without any coordination from neighboring regions
Competitive Reforms to Enable DERs	• Can result in higher volume and more valuable DER deployment which enhances system efficiency for all users	• Early programs require testing and validation to be relied upon at scale	• Best enabled via RTO participation and incorporation of in all-source procurements
Third-Party Energy Efficiency Administrator	• Dedicated entity could develop greater and more innovative EE programs	• Need to ensure effective measurement and verification (status quo EE poses similar challenges)	• Legislation required to create EE administrator and establish funding and oversight model

We find that a measured approach to introducing retail access could offer benefits to South Carolina customers, particularly if initially focusing on enabling partial retail choice for large C&I customers and communities (via Community Choice Aggregations (CCAs)). These consumers are sophisticated buyers, able to take advantage of retail competition to procure electricity supply in alignment with their preferences. More options for retail choice would permit these buyers greater flexibility to control costs and tailor electricity service to their environmental goals and business operations. Enabling partial retail choice would allow South Carolina to compete on a more level playing field with other states to attract investment by these large consumers that can spur economic development in the state.

Initiating utility participation in a regional EIM or RTO market before or at the same time as introducing retail choice will amplify the benefits that could be achieved by partial (or full) retail choice, because these types of competitive wholesale markets offer greater pricing transparency and provide customers and retail providers with access to many more energy supply counterparties and self-supply options. For the same reason, EIM or RTO participation will also benefit municipally owned utilities, electric cooperatives, and communities by offering access to more options for procuring wholesale electricity supply on behalf of their members.

Based on these analyses of retail reforms summarized above, we recommend that South Carolina consider the following options:

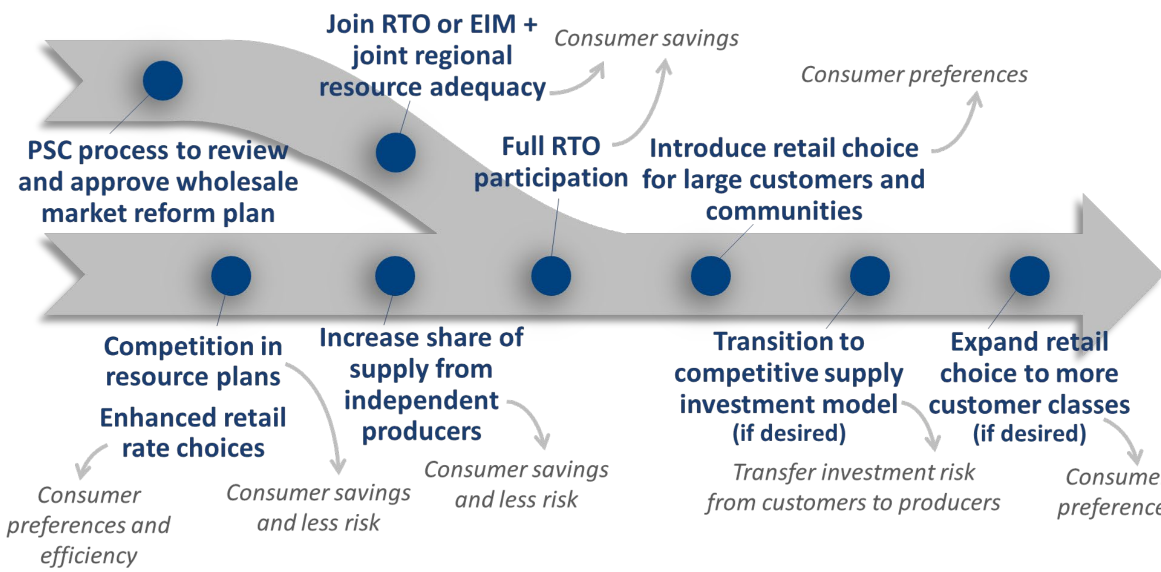
- **Pursue a path toward greater regional coordination via an EIM or RTO wholesale market** to support enabling additional retail rate choices to retail customers. Entering an RTO will immediately increase competitive forces by empowering cooperative and municipal utilities in South Carolina to consider a greater variety of self-supply and contractual options for securing their energy supply.
- **Authorize (and perhaps require) the PSC and regulated utilities to evaluate options for expanded and enhanced retail rate choices** to South Carolina customers, such as increasingly advanced time-varying rates seeking to activate new DR/DER technologies, green tariffs and related green energy options, and other rate designs to enhance efficiency.
- **Introduce partial retail choice for large C&I customers**, enabling businesses that are large, sophisticated energy consumers to negotiate rates, self-supply with clean energy, participate in RTO markets as demand-side resources, and optimize their own consumption.
- **Introduce a path for Community Choice Aggregation**, enabling local communities to pursue environmental goals and negotiate rates.
- **Defer consideration of retail choice for residential and small business customers** until after other reforms are implemented. Revisit the option to expand retail choice to all consumers after gaining experience with wholesale market participation, partial retail choice, and the other market reforms discussed above.
- **Enable distributed energy resources and demand response** from third-party providers to compete in all-source supply solicitation, both within competitive IRP-based all-source procurement processes and within RTO markets.
- **Authorize the PSC to appoint a third-party EE administrator** to support energy efficiency program development 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.

POTENTIAL MARKET REFORM PATHWAYS

The market reforms we examine in this study can interact with one another in ways that are beneficial if they are implemented in a well-structured sequence. Conversely, the set of recommended reforms could interact poorly if implemented out of sequence or if they are not well-designed. Further, the reform path should maintain a self-consistent approach across each stage of sector transition, given the potential for reforms to be paused or concluded midstream.

If South Carolina chooses to proceed with some or all of the market reforms examined and recommended in this study, they should be introduced in a carefully staged fashion. Figure ES-1 below provides a high-level overview of a reform pathway for South Carolina that is likely to achieve immediate benefits, make steady progress toward an increasingly competitive electricity sector that can provide customer benefits, and avoid problematic interactions among the major market reform elements.

FIGURE ES-1: ILLUSTRATIVE PATH TO INTRODUCING COMPETITIVE REFORMS FOR SOUTH CAROLINA



The most logical pathway for South Carolina is to begin with efforts to join or create an RTO, which will provide cost savings for customers in the state and serve as a critical foundation to many of the other market reforms we examine in this study. Once full RTO membership is achieved, it can provide much of the infrastructure needed to enable further reforms for competitive supply investments, partial or full retail choice, and enhancing opportunities for distributed resources and other innovative business models.

Another set of reforms that can be initiated immediately (prior to full RTO membership) relates to enhanced competition for supply contracts under the current IRP model. Subsequent RTO membership would then enhance the range of opportunities available and introduce the possibility of full transition to a competitive investment model.

While we assessed several reform options which would result in varying degrees of change to the electricity sector, our recommendations described above constitute the initial steps along a path that should follow best practice in the sequencing and introduction of various reforms. As such, we do not recommend South Carolina pursue generation divestiture, full reliance on market-based investments for resource adequacy, or full retail choice for all customers at this time. We do recommend that South Carolina join, create, or integrate with a regional wholesale power market that includes regional optimization of transmission usage and commitment, dispatch of generation resources, and regional resource adequacy coordination. These initial reforms would provide the basis from which additional reforms could be pursued in a logical sequence (and in consideration of the complexities and opportunities to mitigate transition risks as discussed in detail throughout this report).

To maximize benefits to South Carolina customers, we recommend that policymakers should determine the most desirable end state along this or a similar reform pathway and then proceed with the reforms under a carefully managed process that follows best practice for mitigating transition risks as discussed more fully in the body of this report.

I. Background

A. Legislative Requirements and Study Process

Pursuant to South Carolina Act 187, the South Carolina Electricity Market Reform Measures Study Committee (the "Study Committee") commissioned Brattle consultants to perform this independent assessment of the benefits of potential electricity market reforms for the state.[15] We assessed a variety of market reform measures, and performed detailed simulations of the electrical system corresponding to alternative wholesale market structures.[16] We structure our recommendations with respect to the context of Act 187, which posed the general question of whether and how market reforms to the electricity sector can benefit South Carolina customers, reduce costs, and protect consumers from excess risk.[17]

Act 187 specifies creation of the Study Committee (consisting of a selection of South Carolina legislators in both the House and Senate) and an Advisory Board composed of participants from utilities, solar developers, consumer advocacy groups, end user representatives, other community groups, and South Carolina utility regulators. It tasks the Study Committee with studying: a variety of enumerated reforms, whether one or more reforms should be pursued, the costs and benefits of any recommended reforms, and development of draft legislation for any recommendations. The Act also directs the Committee to retain an independent consultant to

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[15] South Carolina General Assembly, Act No. 187, Electricity Market Reform Measures Study Committee, signed September 29, 2020.

[16] Following the scope enumerated in Act 187, we assessed: a South Carolina Regional Transmission Organization (RTO); a Southeast RTO with South Carolina; joining an existing RTO; a Southeast energy imbalance market; introduction of competition in generation investment; full and partial consumer retail electric service choice; community choice aggregation; restructured markets and high levels of distributed energy resources; joint dispatch agreements for the Carolinas; and retail rates that more closely align consumer interests with electric system interests. In addition, based on feedback from the study committee and advisory board, we assessed: enhanced regional transmission planning; statewide integrated resource planning; securitization related to thermal plant retirements; and a third-party energy efficiency administrator. Each of these reforms is described in detail in Sections II, III, and IV below.

[17] Though not the subject of this study, the Act 187 was drafted and passed over the course of 2020, a time of change for the utility sector in South Carolina. SCANA and Santee Cooper had abandoned the 2-unit expansion of the V.C. Summer Nuclear Generation Station in 2017, with major financial implications for each. SCANA merged with Dominion Energy in December 2019, and the state legislature assessed for several years whether to privatize Santee Cooper, ultimately deciding instead to focus on oversight reforms. South Carolina electricity customers continue to pay premiums to recover the capital lost in the V.C. Summer project.

advise the Study Committee and produce an opinion on which reforms would benefit South Carolina consumers (i.e., the present report).

Throughout this process, we have served as an educational resource for the Study Committee and its Advisory Board, and have connected them with other experts and practitioners in the industry who offered additional education and perspectives. We assisted the Study Committee with general study scoping and identifying which market reforms in Act 187 (and other reforms requested by stakeholders) should be subject to detailed analysis (including power system modeling). The Study Committee and Advisory Board provided close feedback and support for the execution of this effort throughout. For more information see Appendix D.

B. Overview of South Carolina's Electricity Sector

The electricity sector in South Carolina, similar to that in thirty-three other U.S. states, is based on the vertically integrated utility model with cost-of-service regulated retail rates.[18] Vertically integrated utilities: (i) own and operate (most) generation, transmission, and distribution (with cost recovery through regulated retail rates); (ii) conduct near term operations and long-term generation and transmission planning; (iii) administer interconnection of independent generation; (iv) charge federally-regulated transmission rates for inter-utility trading; (v) purchase or sell wholesale power in wholesale markets and/or bilaterally with neighboring utilities; (vi) perform distribution system planning and operation; and (vii) serve retail customers.

In South Carolina, the Investor-Owned Utilities (IOUs) include Duke Energy Progress and Duke Energy Carolinas (collectively "Duke"), Dominion Energy ("Dominion"), and Lockhart Power Company ("Lockhart"). The South Carolina Public Service Authority ("Santee Cooper") is state-owned and follows some of the same regulatory structure as the IOUs, but has a more complex governance and oversight model based on the recently implemented reforms in Act 135, signed in 2020.[19] Electric cooperatives, owned by their members, and municipal utilities, owned by local governments, also serve a significant proportion of customers in South Carolina. Vertically integrated utilities are responsible for all segments of the electricity value chain from the generation of electricity to final delivery to customers in their service areas, as shown in Figure 1 below.

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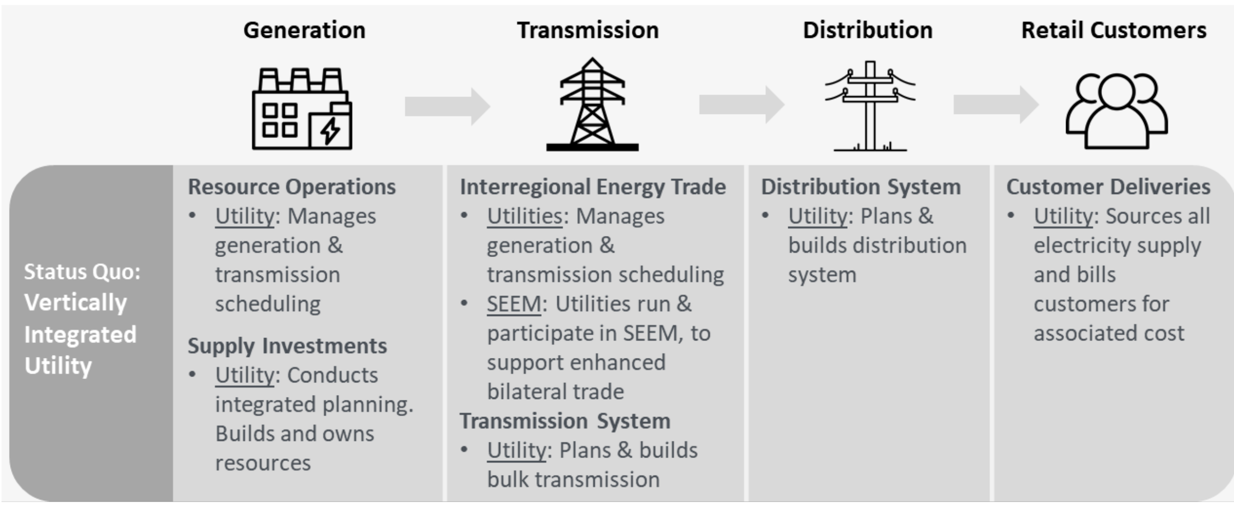
[18] The other U.S. states and the District of Columbia have deregulated their industry structure and introduced retail choice. See Electric Choice, "Deregulated Energy Markets," January 9, 2023.

[19] South Carolina General Assembly, A135, R140, H3411, enacted May 19, 2020.

To provide electricity service, South Carolina investor owned utilities are granted monopoly status in their service territory and are regulated by the South Carolina Public Service Commission (PSC). The PSC is the state-level regulator responsible for adjudicative functions and approves regulated rates of return on investment for vertically integrated utilities, regulates investments in generation and the distribution system, establishes bundled retail rates charged to customers, and approves long-term planning efforts that utilities are required to file periodically known as Integrated Resource Plans (IRPs).

FIGURE 1: SOUTH CAROLINA'S CURRENT SECTOR MODEL WITH VERTICALLY INTEGRATED UTILITIES



Source/Notes: The term SEEM refers to the Southeast Energy Exchange Market. This figure illustrates which roles in each section of the electricity value chain vertically integrated utilities play under the status quo.

As shown in Table 1, the IOUs serve 0.3% (Lockhart), 7% (Duke Energy Progress), 26% (Duke Energy Carolinas), and 27% (Dominion) of South Carolina energy demand directly. Additionally Santee Cooper serves 12%, electric cooperatives serve 23%, and municipally owned utilities serve 4% of South Carolina's retail load. Electric cooperatives receive approximately 80% of their wholesale power from Santee Cooper and 20% from Duke Energy Carolinas while municipalities receive approximately 26% of their wholesale power from Dominion and 74% from Duke Energy Carolinas.

In addition to their role as vertically integrated utilities and distribution providers, Duke, Dominion, and Santee Cooper also act as the Balancing Authorities (BAs) that manage real-time energy generation and supply within their Balancing Authority Area (BAA) of the broader regional bulk transmission system. In their roles as BAs, these same companies support energy deliveries to 8% (Duke Progress), 28% (Dominion), 30% (Santee Cooper), and 34% (Duke Energy Carolinas) of South Carolina's retail electricity customers.

For the purposes of this study, we will discuss the role of these entities both as BAs (collectively, the four companies serve all South Carolina customers in this role) and as vertically integrated utilities. In total, 31 separate utility companies serve South Carolina customers under a range of ownership structures and business models.[20] Figure 2 below shows the balancing areas of the four South Carolina Balancing Authorities.

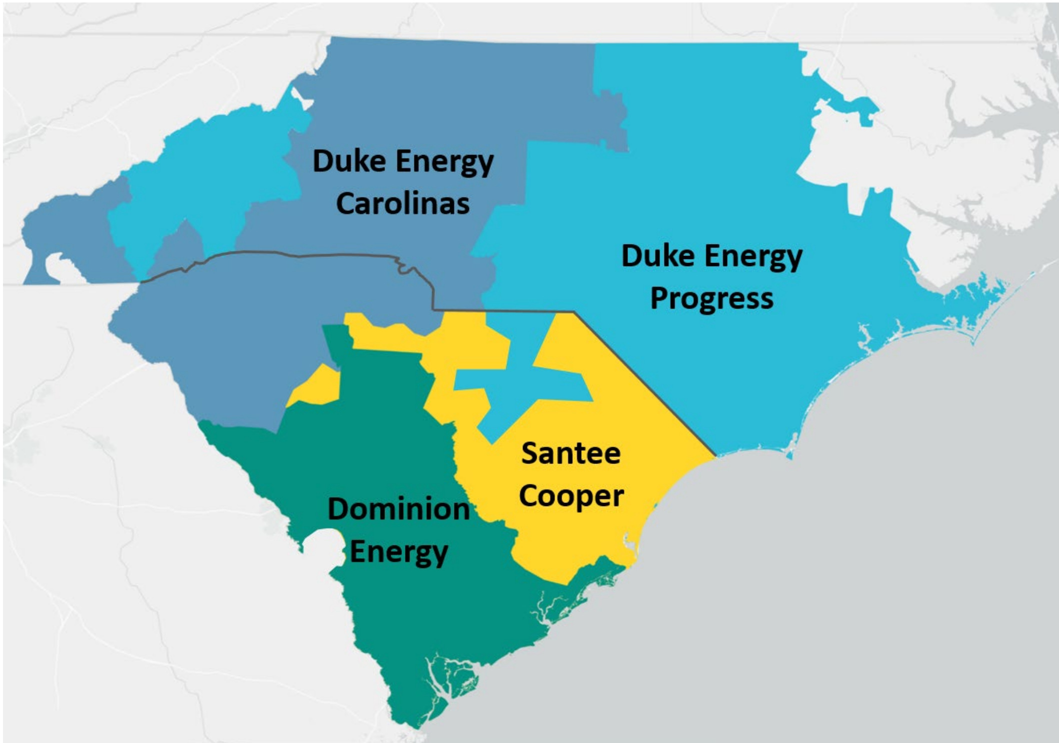
TABLE 1: SHARE OF SOUTH CAROLINA DEMAND SERVED BY EACH BALANCING AUTHORITY AND DISTRIBUTION UTILITY

	Balancing Authorities					
	Duke Energy Carolinas	Santee Cooper	Dominion Energy	Duke Energy Progress	Total	Share of SC Energy Demand
	MWh	MWh	MWh	MWh	MWh	%
Utilities that are also BAs						
Dominion Energy (IOU)			21,411,242		**21,411,242**	**27%**
Duke Energy Carolinas (IOU)	20,440,331				**20,440,331**	**26%**
Santee Cooper (State-Owned)		9,189,290			**9,189,290**	**12%**
Duke Energy Progress (IOU)				5,934,799	**5,934,799**	**7%**
Coops, munis, IOU, and adjustments						
Cooperative	3,688,944	14,384,938			**18,073,882**	**23%**
Municipal	2,229,968		783,157		**3,013,125**	**4%**
Lockhart Power Co. (IOU)	204,662				**204,662**	**0.3%**
Behind the Meter	39,935		39,784		**79,719**	**0%**
Adjustment 2021	768,673	422,127	72,107	182,179	**1,445,086**	**2%**
Total SC Deliveries	**27,372,513**	**23,996,355**	**22,306,290**	**6,116,978**	**79,792,136**	**100%**
Share of Deliveries to SC customers	**34%**	**30%**	**28%**	**8%**	**100%**	

Source/Notes: Energy Information Administration (EIA), Annual Electric Power Industry Report, Form EIA-861, detailed data files, reflects year 2021.

[20] Compiled from Energy Information Administration (EIA), Annual Electric Power Industry Report, Form EIA-861, detailed data files, reflects year 2021.

FIGURE 2: SOUTH CAROLINA BALANCING AUTHORITIES



Source/Notes: S&P Global Market Intelligence, LLC, Mapping Tool.

In addition to the vertically integrated utilities and the PSC, there are several other key players in the electricity sector. Independent Power Producers (IPPs) own and operate unregulated generation (generation that does not have guaranteed/regulated cost recovery) or Qualifying Facilities (QFs) and need to apply to interconnect to the utility transmission system through a utility-administered process. QFs are combined heat and power generators or smaller-scale renewable generation resources owned by IPPs that qualify under the Public Utility Regulatory Policies Act of 1978 (PURPA).[21] IPPs have a smaller role in South Carolina where small combined-heat and power and other IPP capacity is 2,664 MW, or approximately eleven percent of total generation in the state.[22] QFs qualify under PURPA for state-regulated rates based on utility avoided costs and must be included by utilities in their resource mix.[23]

21 The Public Utility Regulatory Policies Act of 1978 (PURPA) a federal legislation which was enacted to encourage fuel diversity by requiring utilities to purchase alternative energy sources thereby opening third-party access to the transmission system and incrementally introducing competition into the electric sector. See Public Utility Regulatory Policies Act (PURPA), Pub. L. 95–617, 92 Stat. 3117, enacted November 9, 1978.

22 U.S. Energy Information Administration (EIA), South Carolina Electricity Profile 2021, November 10, 2022.

23 Qualifying Facilities are grouped into two types of cogeneration and small renewables and enjoy certain benefits under federal, state, and local laws. The benefits that are conferred upon QFs by federal law generally fall into three categories: the right to sell energy or capacity to a utility, the right to purchase certain services from

The Federal Energy Regulatory Commission (FERC) mandates open access transmission and regulates transmission rates for inter-utility (and any unbundled) usage of the grid. The North American Electric Reliability Council (NERC) sets reliability criteria that govern near-term operations and long-term planning of generation and transmission to ensure that utilities maintain an adequate and reliable system.

The federal government establishes federal energy policy (e.g., tax credits for renewables, PURPA, emissions regulations) while the South Carolina state government establishes energy policy for the state, including incentives for certain types of generation assets and demand side management.

C. South Carolina Market Reforms Assessed in this Study

Compared to South Carolina's vertically integrated model where a utility has the exclusive right to serve customers within a defined service territory, other jurisdictions across the U.S. and internationally have introduced varying levels of competition to various segments of the electricity value chain. Introducing competitive reforms into South Carolina may require adjusting the roles and responsibilities of utilities compared to other players, as briefly summarized in Figure 3. For the purposes of assessing the potential benefits and relevance to South Carolina, we structure our assessment into three areas of potential reform, each of which would require different levels of sector reorganization:

- **Wholesale market reforms** are those that could improve the cost-effectiveness of generation resource operations and trade across regions. The primary sector reorganization under this model would be to shift responsibility for generation dispatch from the individual utilities to a regionally coordinated framework. Among these variations, the wholesale Regional Transmission Organization (RTO) market option offers the greatest level of regional coordination and competition. RTO markets serve the energy needs of approximately two-thirds of customers across the U.S., and serve regions with vertically integrated utilities (like South Carolina) as well as regions that have partly or fully restructured into competitive generation and retail choice models.[24] Many states with utilities that are participating in

utilities, and relief from certain regulatory burdens. See Federal Energy Regulatory Commission (FERC), "What is a Qualifying Facility?," updated on June 11, 2021; and Public Utility Regulatory Policies Act (PURPA), Pub. L. 95–617, 92 Stat. 3117, enacted November 9, 1978.

24 ISO/RTO Council, "The Role of ISOs and RTOs," accessed February 7, 2023.

regional wholesale power markets (such as most states with utilities participating in the Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), or the Western Energy Imbalance Market (WEIM) rely on vertically integrated industry structure and a traditional cost of service regulatory model with state-regulated bundled retail electricity rates. In addition to administering energy markets and resource adequacy requirements, these RTOs administer regional open-access transmission tariffs, ensure regional reliability needs, and conduct regional transmission planning.

- **Resource planning and competitive investment reforms** are those that seek to improve the cost-effectiveness of resource investment decisions and shift investment risks away from customers and onto producers. Reforms in this area would create greater opportunities for IPPs to develop and build future generation, storage, and demand response resources instead of relying mainly on the utilities as the only or primary owners and developers of generation and supply resources. These third-party developers would compete to provide the needed resources at the lowest cost to consumers. Variations of this reform range from modest (incrementally introducing competition and shifting a small amount of risk to resource owners) to extensive (relying entirely on market prices to attract investment and shifting all investment risks to resource owners).
- **Retail market reforms** are those that would offer customers greater opportunities to select their retail electricity suppliers based on their preferred resource mix or rate structure. Under different variations of retail market reforms, large customers, communities, or (potentially) even small customers could choose to receive electricity supply from a competitive third-party supplier rather than only from their incumbent utility. Across the U.S., approximately 57% of customer demand is located in states with a competitive retail market model.[25] Depending on how the retail market is established under state regulations, a customer's choice to receive power from another entity could be a reflection of their preferences related to price, rate structure, green energy, pricing risk, customer service, distributed resource programs, or billing interfaces.

These three categories of electricity market reforms are interrelated, chiefly in terms of their natural sequence of introduction. Wholesale market reforms such as participating in an EIM or RTO are typically introduced first, followed by competitive supply investments, and then retail market reforms.

[25] Energy Information Agency (EIA), Annual Electric Power Industry Report, Form EIA-861, detailed data files, accessed February 8, 2023.

FIGURE 3: CATEGORIES OF POTENTIAL ELECTRICITY MARKET REFORMS EXAMINED IN THIS STUDY

	Generation	Transmission	Distribution	Retail Customers
Status Quo: **Vertically Integrated Utility**	**Resource Operations** • Utility: Manages generation & transmission scheduling **Supply Investments** • Utility: Conducts integrated planning. Builds and owns resources	**Interregional Energy Trade** • Utilities: Manages generation & transmission scheduling • SEEM: Utilities run & participate in SEEM, to support enhanced bilateral trade **Transmission System** • Utility: Plans & builds bulk transmission	**Distribution System** • Utility: Plans & builds distribution system	**Customer Deliveries** • Utility: Sources all electricity supply and bills customers for associated cost
Wholesale Market Reforms	**Resource Operations** • JDA, EIM or RTO: Uses regional coordination or marketplace to schedule generation and transmission	**Interregional Energy Trade** • JDA, EIM or RTO: Maximize benefits of regional trade **Transmission System** • RTO: Supports inter-regional transmission planning		
Resource Planning & Competitive Investments	**Supply Investments** • IPPs: Can develop new resources (competing on price)			
Retail Market Reforms				**Customer Deliveries** • Customers: Select retail provider to procure needed supply (compete on price, green, or other values)

Source/Notes: This figure illustrates which roles in each section of the electricity value chain are changed by each area of reform. Blank areas indicate where there are no or minimal changes to the existing industry structure under a given reform area. JDA = Joint Dispatch Authority.

Table 2 further describes the scope of reform questions in each of these three categories, and briefly lists the individual reform options examined in this study. As discussed above, the reform options that we examine in detail were selected in close coordination with the Study Committee and Advisory Board, and aim to reflect the options that offer the greatest relevance and most immediate interest in South Carolina's context.

TABLE 2: ELECTRICITY REFORM OPTIONS EVALUATED IN SOUTH CAROLINA'S CONTEXT

Option	Scope of Reform Questions	Reform Options Evaluated
Wholesale Market Reforms	• How are operational decisions made to schedule generation and transmission? • How is interregional energy trade supported? • How much total supply is needed to maintain reliability? • How is the transmission system planned and built?	• Status quo with vertically integrated utilities • Joint Dispatch Agreement (JDA) • Energy Imbalance Market (EIM) • Regional Transmission Organization (RTO) • Enhanced regional transmission planning (within an RTO)
Resource Planning and Competitive Investment Reforms	• How are supply resources selected? • How is the proportion each technology determined (coal, gas, demand response, batteries, renewable)? • Who owns the supply resources? • Who bears the risk of uneconomic investment decisions?	• Status quo with utility IRP • Statewide IRP across all utilities • Competitive reforms to utility IRP • Transition to competitive supply investments • Securitization of costs related to retiring thermal assets
Retail Market Reforms	• Can customers choose their retail supplier? • For non-shopping customers, how and by who is default retail service provided? • Can customers reflect their own preferences of risk, cost, green • How are customer-owned and distributed resources leveraged and incentivized?	• Partial retail choice (available primarily to large customers) • Full retail choice (including small Commercial & Industrial (C&I) and residential) • Community choice aggregation • Competitive reforms to enable DERs • Third-party energy efficiency administrator

II. Wholesale Market Reforms

A. Overview of Potential Wholesale Market Reforms

The scope of the wholesale market reforms we examine for South Carolina relate to bulk grid operations, the processes by which resources operate and transmission is scheduled, including inter-utility exchanges of energy. Wholesale reforms are therefore focused on opportunities to improve daily operations, expand regional coordination and introduce opportunities for competition, and enhance trade among a broader group of participants. Savings from wholesale reforms are derived from economies of scale related to pooling of resources across many utilities, IPPs, utility customers, public power entities, and others, which yields more efficient resource operations, potentially enabling fewer generators to serve customers than otherwise, and more efficient utilization and planning of transmission infrastructure.

Because wholesale market transactions in the regional grid cross state lines and form part of interstate commerce, these markets are subject to regulation by the Federal Energy Regulatory Commission (FERC). FERC's legislative mandate is to ensure that rates and terms of transmission service and wholesale market transactions are just and reasonable and not unduly discriminatory. FERC oversight applies both to the status quo (in which bilateral wholesale trades are effectuated pursuant to each utility's FERC-filed Open Access Transmission Tariff, or "OATT") as well as to the reforms described below (many of which consolidate rates under a single OATT). State policymakers can influence whether FERC regulation applies on a per-utility basis, or instead applies to a collection of utilities grouped under a wholesale market operator.

The options described here span a "spectrum" of wholesale reforms that have been deployed in North America today as shown in Table 3. These options are:

- **Status Quo**: Utilities are responsible for their own operations within their service territory. Interactions with other utilities are either opportunistic (through bilateral trades) or through (occasionally) coordinated long-range planning. FERC oversees bulk system operations and trade via oversight of the Open Access Transmission Tariff (OATT) of each respective transmission utility, which establishes the terms and rates by which utilities, customers, and power producers may schedule bilateral transactions across the transmission lines.
- **Joint Dispatch Agreement (JDA)**: A JDA more closely coordinates the real-time dispatch of generators between two or more utilities. One of the member utilities (e.g., Duke, which

already uses a JDA across its two utilities) acts as operator and governance is via FERC oversight of the BA's OATT, which references the JDA. A JDA operates in the 5-to-15 minute timeframe utilizing any spare transfer capability between the utilities to meet utility loads by more optimally dispatching the JDA-utilities' online generating units. Savings from energy exchanges among utilities are shared and settled after the fact with a predetermined formula. Individual utilities are generally still responsible for their minute-by-minute balancing and operating reserves.

- **Energy Imbalance Market (EIM)**: An EIM optimizes the real-time dispatch of generators against physical transmission constraints across a broader regional footprint composed of several utilities and introduces an independent operator to optimize the dispatch. It is somewhat similar to the JDA in that individual utilities control unit commitment and trading up until real-time operations, however an EIM adds transmission-security-constrained dispatch and congestion management (and in some cases optimized start-up scheduling in real time for flexible offline generators). It also creates transparent location-specific spot market prices and financial settlements at every location for every 5-15 minute dispatch interval. Utilities in an EIM generally remain responsible for their minute-to-minute balancing and provision of operating reserves. As under status quo and JDA options, FERC continues to regulate the coordinating agreements and the rates and terms (the "tariff") for wholesale transactions.
- **Regional Transmission Operator (RTO)**: An RTO pools all generator operations and wholesale functions including both (1) day-ahead unit commitment and market operations and settlements; as well as (2) real-time dispatch and congestion management. Additional efficiencies are obtained through the consolidation of individual utilities' BAs into a single BA. Both real-time generator dispatch and day-ahead resource scheduling are optimized across the entire footprint using Security Constrained Economic Dispatch (SCED). An RTO also conducts regional transmission planning across its member utility footprint, which can span several states. As with the status quo, JDA, and EIM options, the rates and rules of trade remain FERC-regulated under an OATT; however the filing rights to amend the OATT are held by the non-profit ISO/RTO entity and subject to a set of governance rules that offer an opportunity for a broad set of stakeholders to participate in rule reforms.[26]

[26] Under separate utility OATTs in the status quo, the transmission utility alone holds these filing rights subject to FERC approval. Under an ISO/RTO structure, the ISO/RTO entity holds the filing rights to the OATT and voting rights are allocated more broadly to the transmission owners vs. buyers and sellers seeking to use the transmission lines to trade and deliver power.

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.

We note that there are multiple kinds of RTOs as shown in the spectrum of wholesale market reforms in Table 3 below. These include single-state vs multi-state RTOs, and those operating in states with vertically integrated utilities vs. restructured utilities (or a combination of both). To ensure resource adequacy, utilities can trade firm resource availability ("capacity") in wholesale markets alongside energy. Like energy, capacity can be pooled, either in an RTO or in a purpose-built resource adequacy sharing program. Some RTOs allocate a share of the pool-wide resource adequacy requirement and mandate that utilities meet it through self-supply or bilateral arrangements (a resource requirement approach) while other RTOs host a market for trading capacity (capacity market approach). In Texas, resource adequacy is mediated through shortage pricing in the energy market. The spectrum of wholesale market reforms considered in this study also reflects what has been implemented elsewhere in the U.S., but is not an exhaustive illustration of what is possible. Elements from these approaches used in other regions can be combined in a different combination that most optimally reflect South Carolina's market conditions and addresses the state's needs and preferences.

TABLE 3: THE SPECTRUM OF WHOLESALE MARKET REFORMS AND EXAMPLES

Non-RTO Options				RTO Options				
				Vertically integrated utilities		Restructured utilities		
Bilateral markets	Enhanced bilateral markets	Joint Dispatch Agreement	EIM EIM + Day-ahead market EIM + Resource adequacy	Resource requirement	Capacity market	Resource requirement	Capacity market	Energy-only shortage pricing
South Carolina (before SEEM)	South Carolina (with SEEM)	Duke JDA Colorado JDA	Western EIM EDAM (pending) SPP Markets+ (pending) WRAP (pending)	PJM SPP	MISO	CAISO	PJM NYISO ISO-NE MISO (IL)	ERCOT

Note: This table reflects the dominant regulatory environment in each area however there are smaller exceptions that are not included. CAISO = California ISO, EDAM = Extended Day-Ahead Market, EIM = Energy Imbalance Market, ERCOT = Electric Reliability Council of Texas, ISO = Independent System Operator, ISO-NE =

ISO New England, MISO = Midcontinent Independent System Operator, NYISO = New York ISO, PJM = PJM Interconnection, LLC., SPP = Southwest Power Pool, WRAP = Western Resource Adequacy Program.

Since wholesale markets for power are enabled over regional transmission networks that cover large geographic areas with many utilities, savings related to efficient pooled operations can be enhanced by RTO's regional approach to transmission planning. We therefore also consider options to enhance regional transmission planning in South Carolina and how these options interact with the above wholesale market reforms.

The wholesale market reforms introduce a layer of coordination among utilities that takes the place of obligations and roles currently run internally within the utility. For example, today a utility in South Carolina is responsible for balancing its own supply and demand in real time, reporting to the South Eastern Reliability Council (SERC, the southeastern Regional Entity of NERC) on its performance metrics, and paying any fines when regional or national standards for balancing are not met.[27] Under an RTO, a large portion of this responsibility and risk is transferred to the RTO. The way these roles shift and how they fit in with the overall business of today's utilities is illustrated in Figure 4.

[27] NERC, "Standard BAL-001-2—Real Power Balancing Control Performance," 2015.

FIGURE 4: POTENTIAL ROLE OF WHOLESALE MARKET REFORMS IN SOUTH CAROLINA

	Generation	Transmission	Distribution	Retail Customers
Status Quo	**Resource Operations** • Utility: Manages generation & transmission scheduling **Supply Investments** • Utility: Conducts integrated planning. Builds and owns resources	**Interregional Energy Trade** • Utilities: Manages generation & transmission scheduling • SEEM: Utilities run & participate in SEEM, to support enhanced bilateral trade **Transmission System** • Utility: Plans & builds bulk transmission	**Distribution System** • Utility: Plans & builds distribution system	**Customer Deliveries** • Utility: Sources all electricity supply and bills customers for associated cost
Wholesale Market Reforms	**Resource Operations** • JDA, EIM or RTO: Uses regional coordination to schedule generation and transmission	**Interregional Energy Trade** • JDA, EIM or RTO: Maximize benefits of regional trade **Transmission System** • RTO: Supports regional transmission planning		

Source/Notes: This figure illustrates which roles in each section of the electricity value chain are changed by each area of reform. Blank areas indicate where there are no or minimal changes to the existing industry structure under a given reform area.

In the remainder of Section II we evaluate the advantages and disadvantages of these wholesale market reform options, the implications of their governance models, implementation considerations, and conclude by presenting quantitative net benefits for each reform option. As we discuss in more detail, each of the major reform options also offers distinct choices. For example, the RTO option could be achieved by the state's utilities either through joining PJM, by developing a Southeast RTO, or by evolving SEEM into an Energy Imbalance Market with additional functionality added over time such as a day-ahead market and regional resource adequacy framework, eventually evolving into an RTO.

B. Status Quo

DESCRIPTION OF STATUS QUO IN SOUTH CAROLINA

The utilities in South Carolina serve customer load in their service areas mostly with their own generation. Wholesale trades with other utilities or entities represent an important but relative smaller part of operations compared to generation from their own resources. However, the reliance on wholesale trades varies by utility. Such wholesale trades are conducted on a bilateral basis in markets that range from long-term to hourly and intra-hour. Long-term firm trades can be a helpful supplement to resource adequacy, while trades in the operating time horizon can provide opportunistic cost savings when cheaper generation is available for purchase elsewhere (or provide cost offsets when through revenues from off-system sales to other utilities).

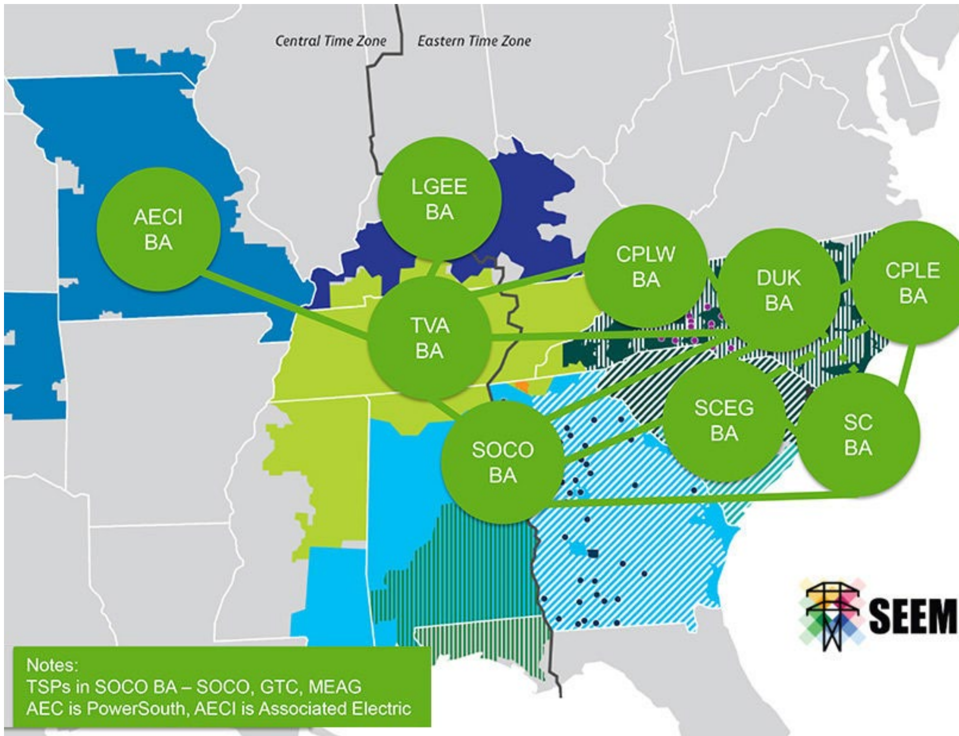
In the minute-to-minute operational timeframe, utilities in South Carolina likewise depend mainly on their own resources to balance load. As explained above, utilities function both to serve customers as well as Balancing Authorities, a NERC role that sets standards for real-time system operations. When demand for electricity rises, each utility dispatches their own generators to increase output in response, which is supplemented by hourly bilateral transactions, ensuring that supply and demand match.[28] In one important operational domain, the South Carolina utilities do pool their generation reserves regionally. The VACAR-South reserve sharing arrangement among South Carolina utilities allows the utilities to share operating reserves to quickly replace the generation from unexpected generator or transmission outages.[29]

The South Carolina utilities participate in the Southeast Energy Exchange Market (SEEM), which launched on November 9, 2022. SEEM is a bilateral-trading platform for matching buyers and sellers of wholesale spot non-firm energy across its footprint. SEEM bilateral trades for energy are finalized close to each 15-minute trading interval (after day-ahead and intra-day trades are completed) and use any available, unreserved transmission without charge. Figure 5 is a map of the SEEM footprint.

[28] The Duke utilities serving South Carolina operate a Joint Dispatch Agreement that includes their North Carolina service areas. They plan to form a single Balancing Authority by 2030.

[29] VACAR-South includes all of the Carolinas, except the portion of Virginia Electric and Power Company's service area in North Carolina.

FIGURE 5: SEEM FOOTPRINT (AS OF FEBRUARY 2021)



Source/Notes: Southeast Energy Exchange Market (SEEM), "[Re: Southern Company Services, Inc. Southeast Energy Exchange Market Agreement,](#)" Docket ER21-1111, filed February 12, 2021. In addition to the utilities shown, Duke Energy Florida, JEA, Seminole Electric Cooperative and TECO Energy joined SEEM expect to start trading in mid-2023.

Utilities benefit from wholesale trades at all time horizons, from years forward to day-ahead and intraday. Ultimately, these cost savings from trade are passed on to customers via rate adjustments. However, there are significant frictions inherent in bilateral trading that limit their scope and benefit, especially in the day-ahead and other time frames that are not covered by the SEEM platform. These frictions include the need to potentially pay a broker or administrative charge, manually arrange the individual trades by telephone or other means, and coordinate transmission scheduling with the utility.[30] For trades that span several utilities, transmission fees must be incurred for each (called "pancaking" of transmission rates). Regional trade therefore yields less consumer benefit than it is theoretically capable of offering.

ADVANTAGES OF STATUS QUO APPROACH

- Utilities (under FERC oversight for transmission operations and under state regulatory oversight for state-jurisdictional activities) retain significant autonomy and discretion, since they are the sole or primary actor in nearly all functions in the electricity industry.

[30] Prior to SEEM, real-time bilateral trades also included tariff wheeling fees.

- Some level of inter-utility efficiencies achieved through Duke's two-utility JDA and the multi-utility SEEM bilateral market platform.

DISADVANTAGES OF STATUS QUO APPROACH

- Utility-specific OATT and point-to-point transmission rights and scheduling impose high transaction costs and the potential for excess tariffs that produce impediments for cost-effective trade and use of the transmission system, particularly for trade and transactions that might otherwise be scheduled by small utilities, individual consumers, and independent power producers.
- Foregoes significant cost savings that can be derived from pooled operations and planning over a broader geographic footprint.
- Requires more generators or other resources to meet the same level of reliability compared to pooled regional resource adequacy scenarios, such as an RTO or a regional resource adequacy market, that can take advantage of the diversity of loads and resources in a larger geographic region.
- There are fewer operational options available to remediate supply shortages or other emergency conditions.[31]
- FERC OATT oversight model retains all "filing rights" with the transmission-owning utilities (both under utility-specific OATTs and under the SEEM market rules), which limits opportunities to consider the priorities of IPPs, consumers, state governments, or other stakeholders in updating FERC-approved rules of transmission of use and trade.
- The functionality of SEEM is limited compared to other regional market options. SEEM does not issue dispatch instructions, does not optimize generation dispatch, manage transmission congestion, or facilitate reserves sharing between its utility members. Parties to a transaction must take action on their own to finalize the sale. SEEM prices are trade-specific, which means, unlike in EIM or RTO markets, SEEM does not yield transparent real-time market prices at which non-utility members of the industry could transact.
- Trade volumes in SEEM have been limited in its first six months of operation, including certain days in which no power is traded among SEEM participants. SEEM's performance during

[31] For example, in the PJM RTO, emergency conditions in the Mid-Atlantic can be mitigated by excess generation in Illinois or demand response in Ohio. The tools available to the system operator feature more geographic and technological diversity, which tend to be less susceptible to shared points of failure.

Winter Storm Elliot has been criticized, as volume of cleared energy was negligible during the storm.[32]

- The governance of SEEM has been criticized on grounds that large utility members hold more control over SEEM than other market participants, and its governance would not meet the standards of inclusiveness and sectoral neutrality that FERC sets for RTOs.[33]

C. Joint Dispatch Agreement

DESCRIPTION AND RELEVANT CASE STUDIES

In a Joint Dispatch Agreement (JDA), the dispatch of all of the online generation of multiple utilities is pooled and optimized to serve their combined load. This pooling allows more efficient dispatch of generation across a wider fleet, which reduces costs. The JDA is the simplest of the wholesale market reform options available to South Carolina, and would be relatively expeditious to implement following development of consensus among member utilities, especially since Duke already runs a JDA for its two utilities. A JDA designates one utility to administer operations and dispatch, and settle net exchanges of electricity among the utilities (while stopping short of calculating public prices) so that cost savings can be shared. The JDA is both simple and a significant increase in functionality over SEEM, but the JDA's still-limited functionality (compared to other market reform options) means it offers the lowest net benefits to South Carolina of the wholesale reform alternatives evaluated here, and could even result in a net cost. The JDA only addresses near-term (and real-time) generation dispatch, which also provides some reliability benefits.

To illustrate the pooling benefit of a JDA, consider two utilities that each serve only their own demand. One utility may have only costly generation available to meet its demand, while another utility has surplus low cost generation. The customers of each utility would benefit by trading, the first utility produces less of its costly supply and buys the cheap surplus from the second

[32] See, for example, RTO Insider, "GCPA Panelists Go One on One Over SEEM Proposal", April 3, 2022; RTO Insider, "Southern Co. Takes Heat over SEEM, Opposition to RTO", May 16, 2022; S&P Global Market Intelligence, LLC, "Southeast Energy Exchange Market Addresses Reports of Limited Trading Activity", February 13, 2023.

[33] As noted by FERC Commissioner Alison Clements in a recent dissent: "*NFEETS [Non-Firm Energy Exchange Transmission Service, a prerequisite of SEEMS participation] is only available to SEEM participants, and participation in SEEM is not open. Rather, a prospective participant must, among other things, execute enabling agreements with three counterparties who are already SEEM participants, and obtain the countersignature of the Participant Agreement by the SEEM Agent, who is controlled by an Operating Committee composed of SEEM Members*." Federal Energy Regulatory Commission, "Order Accepting Joinder Agreements and OATT Revisions," 181 FERC ¶ 61,275 in FERC dockets ER23-323, ER23-324, ER23-325, and ER23-338, issued December 30, 2022.

utility, while the second benefits from profitable sales of generation that otherwise would not have been utilized. Ultimately, these cost savings from trade are passed on to customers through fuel and purchased power cost adjustments in retail rates.

While such trades currently can also happen bilaterally under the Status Quo, there are significant frictions inherent in bilateral trading, as discussed in the status quo section above. By contrast, a JDA accomplishes an efficient trading outcome automatically (sending out a real-time dispatch signal to each generator) and using pre-determined settlement rules to share savings. There is no need to match individual buyers and sellers, negotiate a price, pay a fee (except the relatively low JDA administrative fee), reserve transmission, or even recognize and approve the transaction. This means trading frictions are significantly reduced within the JDA footprint. The JDA also includes provisions that set a uniformly low or zero charge for transmission utilization for real-time trades within the JDA. The JDA is therefore more efficient than a bilateral trading environment, even one that is enhanced by SEEM.

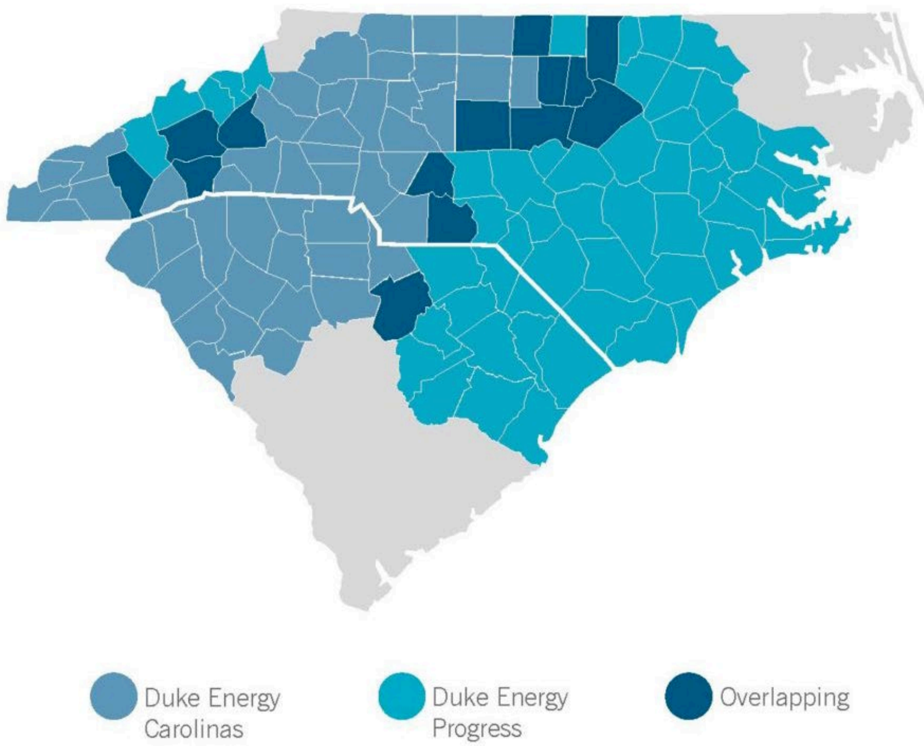
Since JDAs typically use only zonal representations of the transmission network, and cannot always optimize dispatch to the full transmission network availability, their efficiency in pooling online generation is not as effective as the more sophisticated transmission-security-constrained optimization used in the EIM or RTO options (discussed below). Further, the JDA (and the EIM) only pool generation that is online during real-time operations (after utilities have already prepared their day-ahead schedules for meeting their load by bringing generators online and offline). There are major additional efficiencies that are generated by optimizing the day-ahead scheduling process in an RTO setting. Under the JDA and EIM, trade that would require modified generation commitment is subject to the high-friction bilateral trading environment and is unchanged from the Status Quo. In an RTO (or an EIM that includes day-ahead commitment), by contrast, both the day-ahead and real-time generation commitment and dispatch function are optimized across the entire market footprint.

In most JDAs, the minute-to-minute load and supply balancing (i.e., the BA functionality and responsibility) is still conducted by individual utilities. Therefore, the JDA per se does not yield the cost savings and efficiency benefits of pooling operating reserves and consolidating BA functions. While the JDA and its designated operator have no formal reliability responsibility, they do assist with real-time operational reliability by increasing cross-utility liquidity and therefore also increase the options that are quickly available to dispatchers. In some cases a JDA is combined with consolidation of the JDA members into a single BA, in which case such pooling benefits do accrue.

JDA agreements are regulated by FERC and administered by the utility signatories. Other market participants within the JDA footprint (IPPs, distribution-only utilities, etc.) do not have a formal stake regarding the policies and governance of the JDA.

JDAs have been deployed in various contexts. Duke's utilities currently operate under a JDA spanning Duke Carolinas and Duke Progress in both North and South Carolina as shown in Figure 6. The Duke JDA includes only a single corporate parent, but cross-company JDAs also exist—such as with Xcel Colorado, Platte River Power Authority, and Black Hills Colorado Electric, which until recently operated under a JDA managed by Xcel (which also served as a common Balancing Authority).[34]

FIGURE 6: DUKE ENERGY JDA SPANS DUKE ENERGY TERRITORIES IN BOTH SOUTH CAROLINA AND NORTH CAROLINA.



Source/Notes: Duke Energy, "[Economic Development—The Carolinas](#)," accessed January 21, 2023.

POTENTIAL ADVANTAGES

The advantages of the JDA are:

- Reduces barriers to trade by automatically effectuating trades through centralized dispatch and pre-determined settlement and pricing rules

[34] In August, 2022, Colorado Springs Utilities left the JDA to join the SPP Western Energy Imbalance Service (WEIS). The remaining members plan to join WEIS in April, 2023, which will end their JDA.

- Limited geographic scope compared to the EIM and RTO options yields straightforward setup and administration.
- Since the JDA designates one of its members to operate it, there is no need to create, manage, and govern an independent entity. Achieving consensus among the limited number of members is simpler than in a larger market. Further, the flexibility afforded in developing the settlement price may help members avoid concerns about market power (and related administrative burdens, such as requesting market based rate authority from FERC).

POTENTIAL DISADVANTAGES

The limited functional and geographic reach of the JDA option results in several notable disadvantages:

- The net benefits are smaller than for the EIM and RTO options, which cover a larger set of functions and, typically, a larger geographic footprint.
- Without independent administration, members and other market participants may not be confident that conflicts of interest are resolved in an unbiased way (especially when the operator needs to make manual dispatch decisions). Further, members may need to provide market-sensitive data to the operator that could provide a competitive advantage to them (or require burdensome firewalls to prevent such advantage).
- Market prices are not established and posted publicly, thus foregoing the broader market advantages of transparent wholesale market pricing.
- Since the JDA governance is not managed through a formal stakeholder process and is limited only to the participating utilities, the arrangement is not as scalable as other market reform options.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

Development of a JDA would proceed in three stages: negotiations among the members; regulatory approvals at the state and federal level; and implementation of software and business processes. The Xcel Colorado JDA, which took about three years from conception to operations, can provide an illustrative case study:

- Discussions among the members took several months (from mid to late 2014).
- The regulatory process took a little over a year (the first regulatory filings were submitted to FERC in October 2014, and FERC finally approved the JDA in February 2016).
- JDA operations commenced over a year later (on June 1, 2017).

Most JDAs are operated internal to a common holding company, and it is difficult to precisely estimate their administrative cost. [35] While their limited size means that annual costs are spread over relatively few customers (compared to other wholesale market reform options), their simplicity means those costs are relatively low. For the purposes of this assessment, we assume a low-end annual administrative cost of $2 million in $2022 as indicated by the $0.50 per MWh per transaction for the Colorado JDA in 2016 together with estimated JDA transaction volumes in South Carolina.[36] To account for the potential increased cost from the larger size of South Carolina's electrical system (roughly double the size of the Colorado JDA), we use a high end estimate of $4 million.[37]

D. Energy Imbalance Market

DESCRIPTION AND RELEVANT CASE STUDIES

Like a JDA, an Energy Imbalance Market (EIM) jointly optimizes the real-time output of generators from a number of utilities to meet their combined load (ideally across a wide, multi-state area).[38] However, the EIM introduces new features that extend beyond the JDA: (a) an independent entity to administer operations, with defined governance procedures; (b) publication of wholesale market prices at every location and for every 5-minute interval that are used to settle net exchanges of energy among utilities (or any independent generators); (c) more sophisticated nodal (security-constrained) optimization of dispatch making full use of available transmission; and (d) optimization of flexible real-time scheduling for quick-start generators. While the EIM, like the JDA, focuses on the real-time operating horizon, it still leaves the minute-to-minute balancing up to the individual utilities and/or Balancing Authorities. The EIM offers more functionality than a JDA, but it lacks important features of an RTO, and so offers lower net benefits than an RTO.

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[35] The Xcel Colorado (aka Public Service Company of Colorado) JDA fee was $0.50/MWh per transaction in 2016. Note that the JDA charge for Xcel Colorado included recovery of capital costs. Source: Colorado Public Utilities Commission (CO PUC), Recommended Decision Of Administrative Law Judge Mana L. Jennings-Fader Granting Application In Part, Addressing Treatment Of The Joint Dispatch Agreement, Ordering Accounting Treatment, And Ordering Public Service To File Reports, Proceeding No. 16A-0276E, Page 15, November 30, 2016.

[36] In our 2030 simulation scenario, South Carolina has a total of 90,370 GWh of annual load, and the JDA case had 2,564 GWh of transactions among members.

[37] Guidehouse and Charles River Associates, "Southeast Energy Exchange Market: Market Benefits and Non-Centralized Costs Evaluation", November 18, 2020, Page viii.

[38] The term "imbalance" refers to real-time deviations relative to the day-ahead and intra-day supply/demand balance and trades that were scheduled prior to real-time operations. Imbalance occurs when generators produce more or less energy than scheduled, or consumers use more or less energy than scheduled.

An EIM typically calculates and publishes prices for each location at 5-minute intervals. These prices (called "locational marginal prices" or LMPs) are formulated in essentially the same way as energy prices in an RTO. LMPs are closely related to the marginal cost to serve the next increment of load at a location. Inter-utility exchanges are effectively settled on 5-minute intervals using these prices and each utility is credited according to the output of their generators and the price at the corresponding locations, and likewise they are debited according to their consumption at each location times the price there. This pricing mechanism also results in congestion charges, with revenues that are refunded according to various sharing formulas.

An EIM can make full use of the transmission grid in formulating dispatch instructions, using a sophisticated nodal (security-constrained) optimization that considers the actual physical capabilities of the transmission network. This yields more efficient real-time pooling than a JDA. However, the EIM (like the JDA) option has the drawback of only optimizing the small portion of generation that is available for redispatch in real-time, after utilities have already prepared their day-ahead and hour-ahead schedules for meeting their own load—a significant loss in pooling benefits and functionality compared to an RTO. Finally, the EIM is like a JDA in leaving the minute-to-minute balancing up to the individual utilities (who typically are the Balancing Authorities), foregoing the benefits of consolidated BA operations and pooled reserves that an RTO provides.

The EIM does not generally have formal reliability responsibility; however, it does provide utility dispatchers with a larger range of options to react to real-time contingencies relative to the Status Quo. By having Security Constrained Economic Dispatch across the market footprint, imbalances are better managed by an EIM and it enables greater ability to manage real-time flows from a more diverse set of resources (both supply and demand side). Additional reliability benefits include enhanced situational awareness of the system; potentially fewer emergency events; faster identification, dispatch, and delivery of replacement generation after shared contingency reserves are depleted and when contingencies are encountered beyond reserve obligations; and greater integration of variable energy resources.[39]

Policymakers with extended reform timelines can view the EIM as an incremental step in the gradual development of an RTO, as illustrated by history. In SPP, the RTO's members first formed an EIM-style market in 2007 and, after realizing the operational benefits under a full RTO market

[39] Federal Energy Regulatory Commission, Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market, Staff Papers, February 26, 2013.

structure, in 2014 expanded functionality to include a day-ahead energy market.[40] A similar pattern may be playing out now again in the West. The California Independent System Operator (CAISO) and Pacificorp started the Western EIM (WEIM) in 2014, which has since expanded geographically to cover much of the West. CAISO and Pacificorp have most recently committed to add day-ahead functionality to WEIM through an Extended Day Ahead Market (EDAM).[41] Relatedly, the Mountain West Transmission Group of utilities, formed in 2013 to explore pooled operations, effectively evolved into the Western Energy Imbalance Service (WEIS), a standalone EIM operated by SPP that was launched in 2021.[42] SPP and the WEIS members later initiated ongoing discussions to convert much of WEIS into a new Western RTO, while SPP has simultaneously proposed a new "Markets+" non-RTO construct in the West that would include a day-ahead market.[43]

The Western examples show that an existing RTO can offer EIM functionality to utilities outside the RTO. Under such a scenario, utilities outside the RTO can also pool real-time operations with the RTO (but without joining the RTO). The WEIM today has almost twenty member utilities representing 79% of the load in the Western Interconnection, with annual savings approaching $1 billion (see Figure 7 below), and a day-ahead construct called the Extended Day-Ahead Market (EDAM) is being developed, with go-live targeted for 2024.[44] The EDAM is estimated to yield $543 million in operational savings in addition to today's savings from WEIM. Given the EIM benefits experienced in the West, CAISO and SPP are both working with non-member utilities to explore expansion into a multi-state RTO, and Nevada and Colorado have mandated that their utilities join wholesale markets.[45]

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[40] CAISO, ERCOT, and PJM likewise launched with only real-time markets (albeit with consolidated balancing areas, unlike SPP) before they initiated day-ahead markets. SPP operated across several balancing authorities as an RTO with only real-time energy markets (analogous to an EIM structure) from 2006 until 2010, when the utilities consolidated under SPP as a single Balancing Authority. Federal Energy Regulatory Commission, "SPP—Federal Energy Regulatory Commission," accessed February 16, 2023.

[41] For example, see American Public Power Association, "PacifiCorp Agrees to Join California ISO's Extended Day-Ahead Market," December 13, 2022.

[42] Mountain West Transmission Group, "Frequently Asked Questions," updated January 5, 2017; J. Tsoukalis, et al., Western Energy Imbalance Service and SPP Western RTO Participation Benefits, The Brattle Group, December 2, 2020; SPP, "WEIS – Southwest Power Pool," accessed February 16, 2023.

[43] J. Tsoukalis, E. Bennett, Benefits of the SPP RTO Expansion into the WEIS Footprint, The Brattle Group, September 20, 2022; SPP, "RTO West—Southwest Power Pool," accessed February 16, 2023; SPP, "Markets+ – Southwest Power Pool," accessed February 16, 2023.

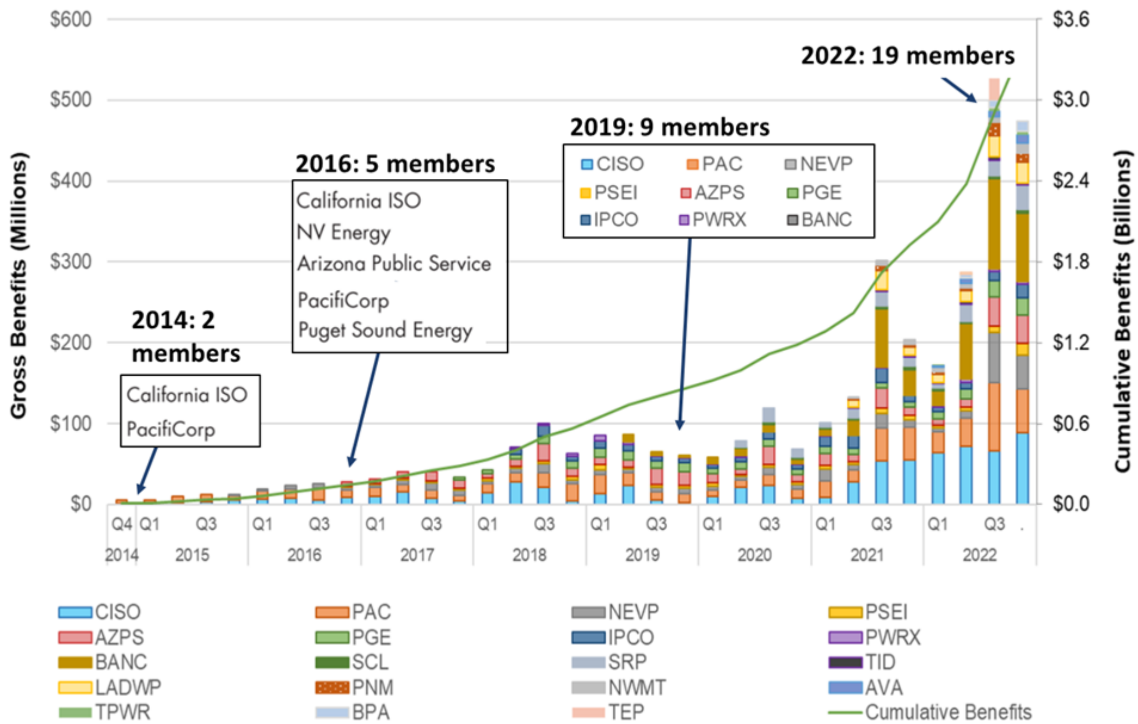
[44] CAISO, "EDAM: Extended Day-Ahead Market," accessed February 16, 2023.

[45] D. Hurlbut, et al., Impacts of Expanded Regional Cooperation on California and the Western Grid, National Renewable Energy Lab, January 13, 2023; SPP, "Markets+—Southwest Power Pool," accessed February 16, 2023.

As noted, there are currently two EIMs in operation in the United States: the CAISO-run Western Energy Imbalance Market (WEIM), and the SPP-run Western Energy Imbalance Service (WEIS). In each case, significant production cost savings are evident (for example, see Figure 8 below). In justifying their approval of participation in the WEIM and WEIS, state commissions cited operational efficiencies from pooled dispatch, benefits in reducing the need for certain reserves products, improved integration of low-cost renewables, and expanded options for achieving reliability.[46] WEIM also claims reductions in carbon emissions associated with reduced curtailments.

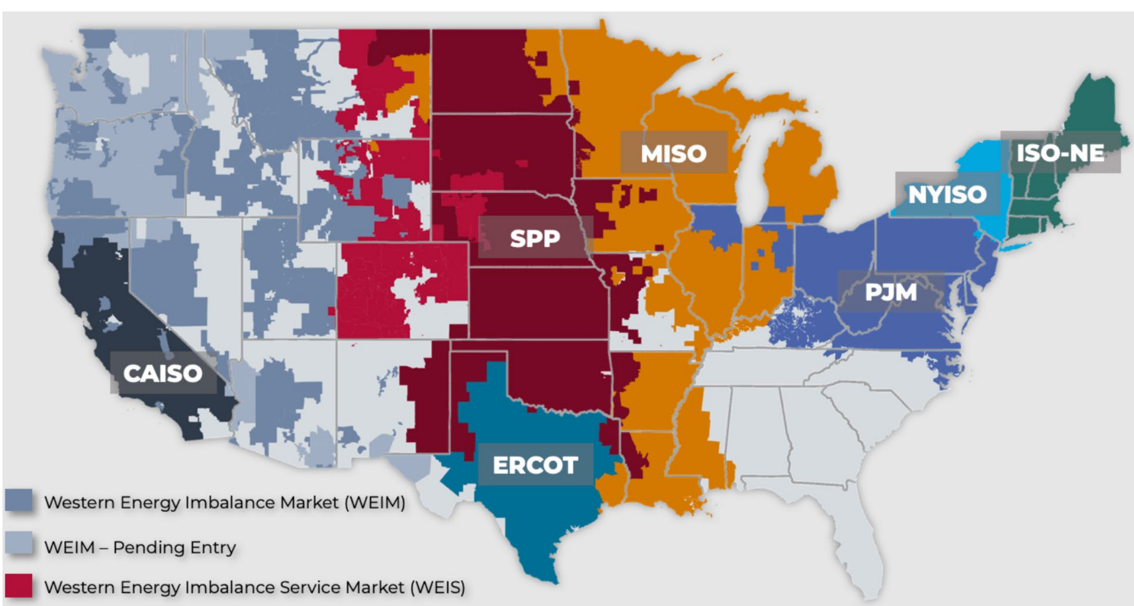
46 For example, see state commission orders accepting aspects of EIM participation in: Nevada Public Utilities Commission, Docket 14-04024, August 27, 2014; Arizona Corporation Commission, Docket E-01933A-20-0039 Decision 77746, September 22 and 23, 2020; and Idaho Public Utilities Commission, Order 33627 Case IPC-E-16-19, January 31, 2017.

FIGURE 7: BENEFITS OF WESTERN ENERGY IMBALANCE MARKET GREW EXPONENTIALLY WITH INCREASED MEMBERSHIP



Source/Notes: Western EIM, "[Western Energy Imbalance Market Benefits: Fourth Quarter 2022,]()" January 31, 2023.

FIGURE 8: CAISO'S WESTERN ENERGY IMBALANCE MARKET AND SPP WESTERN ENERGY IMBALANCE SERVICE IN THE CONTEXT OF RTOS



Source/Notes: Note that light blue areas listed as "pending entry" are currently operating as part of WEIM. Clean Energy Buyers Association, "Organized Wholesale Electricity Markets," 2022.

EIMs potentially span many utilities and states, and so they face some of the same governance requirements as an RTO. Therefore, their governance is carefully designed to facilitate independent policymaking, to give all stakeholders a voice, and to ensure independence from any one member or sector. The EIM entity itself has "filing rights" over the rates, terms, and conditions in its tariff on file at FERC.

As illustrated by the JDA and EIM cases described above, utilities often consolidate their operations to enjoy the benefits of pooled operations without forming an RTO. Such pooling also can be accomplished in a peer-to-peer collaboration with RTOs. For example, CAISO's Western EIM is a conventional EIM structure that is also an operational extension of the existing CAISO RTO real-time energy market, and shares many of its energy market features.[47] The EIM utilities enjoy the operational benefits of pooling with CAISO's real-time energy market without actually joining the RTO as members.

Resource adequacy consolidation is also possible (although no RTO is currently part of such services), as illustrated by the nascent Western Resource Adequacy Program.

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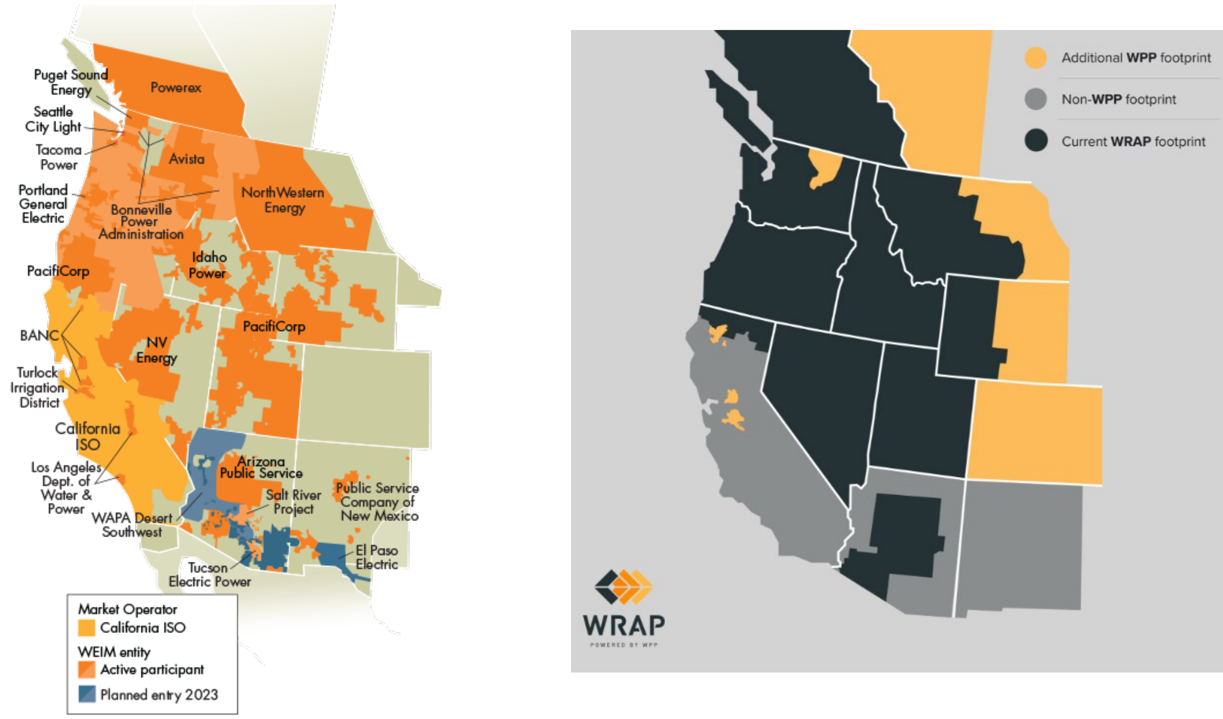
[47] While CAISO is technically an Independent System Operator (ISO) and does not meet FERC's current governance criteria to be an RTO, we will refer to it as an RTO for the purposes of this section.

FIGURE 9: CAISO'S CONSOLIDATED EIM SERVICE OUTSIDE ITS RTO (LEFT) AND THE POOLED WESTERN RESOURCE ADEQUACY PROGRAM (RIGHT)



Source: CAISO, "About—Western Energy Imbalance Market," 2023; Western Power Pool, "Western Resource Adequacy Program—WRAP Area Map," 2021. Both accessed February 11, 2023.

South Carolina could initiate discussions with PJM in pursuit of a similar approach of consolidating energy market and resource adequacy functionality without becoming full RTO members. This approach yields the benefits of pooled functionality without subjecting every aspect of wholesale operations to regional and FERC governance. The functions that could be consolidated with PJM:

- **Shared resource adequacy:** following the example of the Western Resource Adequacy Program (WRAP, pending filing with FERC, administered by SPP but not consolidated with it), South Carolina could pool resource adequacy requirements with other areas (including potentially PJM), thereby yielding significant investment savings. This function is made simpler by consolidating dispatch and scheduling of generation across the same area to effectuate the potential resource adequacy needs in actual operations.
- **Consolidated EIM**: following the example of WEIM, this would jointly optimize just the real-time energy market between South Carolina and PJM. This yields savings when real-time operations deviate from the day-ahead scheduling plan.
- **Consolidated day-ahead energy market**: this would follow current plans to extend WEIM ("EDAM") and WEIS ("Markets+") to include a day-ahead generator scheduling function. Pooling generator schedules yields major savings in fuel costs.

POTENTIAL ADVANTAGES

The potential advantages of an EIM are:

- **Operating efficiency** that is achieved by pooling real-time dispatch across many utilities and removing barriers to efficient trade. In the real-time operating horizon, a utility that can more cheaply buy from other members rather than self-generating is automatically dispatched to that outcome with minimal friction. The reverse is also true for utilities that can cheaply produce excess power. The EIM also removes some "pancaked" transmission rates within its footprint, further reducing trade friction.
- **Transparent prices** provide public benchmarks for planning and bilateral trades at every time horizon, from hourly and day-ahead to long-term PPAs.
- **Increases ability for consumers, public power, and independent power producers to engage in voluntary transactions** in real-time at transparent prices and with equal access to the transmission system.
- **Independent administration and governance** means no one utility or other member is advantaged in the administration of the system. Natural conflicts of interest in utilization of transmission and generation are resolved programmatically in favor of economic efficiency, rather than in favor of the interested party who is operating the system. The rules according to which the independent administrator acts are themselves subject to a consensus-building and decision-making governance process, regulated by the FERC.
- The **relatively simple functionality** of an EIM compared to an RTO makes it easier and lower cost to launch an EIM (both in terms of consensus building and business-process implementation), and easier to reverse course if the benefits fail to materialize. EIM can therefore offer an incremental first step towards greater regional integration. If South Carolina took this initial step to create an EIM (e.g., with other SEEM members) and benefits prove to exceed costs in the first years of EIM operations, state policymakers could then consider taking steps to additional wholesale market reforms.[48]

[48] There is precedent for this approach in other jurisdictions. For example, when Dominion Virginia/North Carolina joined PJM, the Virginia regulator required the utility to analyze benefits and costs each year and report to the regulator. Similarly, the WEIM publishes benefits and costs each quarter, and SPP published benefits of its transition from an EIM-style market to an RTO. See Dominion Energy, "Dominion Applies to Join PJM Interconnection", June 27, 2003; Western Energy Imbalance Market (WEIM), Western Energy Imbalance Market Benefits Third Quarter 2022, October 31, 2022; and SPP, 2021 Member Value, April 6, 2022.

POTENTIAL DISADVANTAGES

Potential disadvantages of an EIM include:

- An EIM lacks several key aspects of the functionality of an RTO, and so foregoes the value achieved from scheduling generators via pooled day-ahead unit commitment, provision of centralized ancillary services, balancing area consolidation, and regional transmission planning.
- The functionality of the EIM is less than that of an RTO, while the implementation complexity of creating a new EIM is greater than joining an existing RTO (since, unlike in the West, the EIM membership option is not already available from RTO market operators).

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

As with other wholesale market reforms, implementation of an EIM can be split into consensus-building and development of founding governance agreements; regulatory approvals; and business process implementation.

Because there is no existing EIM that South Carolina utilities can join, South Carolina's primary options are to develop a new EIM in the Southeast, or to partner with PJM to form a new EIM that is consolidated with a neighboring RTO. In the former case, the membership could save cost and implementation time by subcontracting with an existing RTO (such as SPP, MISO, or PJM) to host the operational infrastructure, as the WEIS has done with SPP. Forming a Southeast EIM could be a practical solution assuming that neighboring utilities and their regulators in nearby states such as North Carolina, Tennessee, and Georgia were willing to commit effort to pursuing the approach. As part of the present assessment, we evaluated the net benefits of an EIM with the same footprint as today's SEEM, but recognize that an EIM could start out with a smaller footprint.

Recent EIM development efforts have leveraged existing RTO systems to deploy at relatively low cost. The WEIM implementation cost was estimated at $20 million, while WEIS was estimated at $9.5 million.[49] Less recently, SPP's initial 2007 implementation of an EIM cost $33 million.[50]

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49 CAISO, "Re: California Independent System Operator Corporation Filing of CAISO Rate Schedule No. 6488," January 29, 2021, Page 3, Docket ER-21-1003; Federal Energy Regulatory Commission, "Order Accepting Proposed Tariff", 173 FERC ¶ 61,267, Docket No. ER21-3-000, issued December 23, 2020.

50 SPP, "Markets+ Proposal", November 30, 2022.

Today, WEIM covers nearly 80% of the WECC and has a $15.3 million annual budget.[51] WEIM has a similar size to the Southeast. WEIM could therefore be comparable in operations and cost to an EIM for the Southeast that, like WEIM, is operated by an existing RTO, thus offering economies of scale and minimal setup cost. We take the WEIM budget as an approximate indication of the potential low end of administrative costs for a Southeast EIM, with South Carolina's 13% share of costs totalling $2 million.[52] The WEIS annual budget of $5 million covers a load somewhat smaller than South Carolina, and can serve as an indicator of the approximate high end of the range of potential EIM administrative costs, particularly in scenarios in which South Carolina starts an EIM that is initially smaller.[53]

The West has been exploring greater regional coordination for decades, including consolidating balancing areas, implementing JDAs, shared reserves agreements, and other such arrangements. In fact, EIM discussions in the West among state governments, utilities, and industry experts started in earnest in 2011.[54] Those discussions laid the groundwork for the development and growth of the two current EIMs, WEIS and WEIM. These provide instructive case studies for the implementation timeline to roll out an EIM, as summarized in Table 4. The timeline is split into regulatory approvals (at both the federal and state level, although only FERC filings are referenced in the historical record) and business process implementation.

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[51] CAISO, "Confidential Position Specification: Independent Non-Executive Governing Body Member (WEIM)", March 2023, Page 4.

For WEIM budget, see: CAISO, "2023 Budget and Grid Management Charge Rates", December 2022, Page 37.

[52] By share of Southeast coincident peak. See Appendix A, page A-2.

[53] SPP, "Western Joint Dispatch Agreement," 2019;

SPP, "Benefit Of The Market: Western Energy Imbalance Service (WEIS)", March 27, 2023, Page 8.

[54] Milligan, M, et al., Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection, NREL, March 2013.

TABLE 4. TIMELINES FOR LAUNCH OF WESTERN EIM AND WESTERN EIS

	WEIM	WEIS
Consensus building and initial agreements	Close to two years: • First conceptual proposal in March, 2012 (following sustained discussion among state commissioners, governors, and the WECC in 2011)[55] • First straw proposal in April, 2013 • Draft tariff language finalized January, 2014	Close to one year: • First conceptual proposal published in June of 2019[56] • First participation agreements with members in September, 2019[57] • Draft tariff language finalized September, 2019
Regulatory approvals	About one and a half years: • Initial implementation agreement filed in March, 2013 • EIM rules filed with FERC on April 16, 2014 • Final approval in October, 2014[58]	About 10 months: • EIS Tariff filed with FERC on February 21, 2020 • FERC approval on December 23, 2020
Business process implementation	About one and a half years: • Implementation began February, 2013[59,60,61] • EIM operations launched November, 2014	About one and a half years: • Project initiated September, 2019 • EIS operations launched February, 2021[62]

E. Regional Transmission Organization (RTO)

DESCRIPTION, RELEVANT CASE STUDIES, AND STUDY SCENARIOS

A Regional Transmission Organization (RTO) is an independently governed and administered entity that executes several key functions on behalf of its member utilities, essentially pooling all wholesale functions: (a) reliably operating the BAA with optimized scheduling and dispatch of generators and demand response within transmission limits; (b) ensuring members have enough generation installed to meet demand effectively all the time ("resource adequacy"); (c) providing

55 CAISO, CAISO Response to Request from PUC-EIM Task Force, March 29, 2012.

56 SPP, A Proposal for the Southwest Power Pool Western Energy Imbalance Service Market (WEIS), 2019.

57 S&P Global Intelligence, LLC, "Three regional utilities announce decision to join Southwest Power Pool market," accessed January 24, 2023.

58 Federal Energy Regulatory Commission, Order on rehearing, clarification, and compliance re California Independent System Operator Corporation, Docket No. ER14-1386-001, October 20, 2014.

59 CAISO and PacifiCorp, Energy Imbalance Market Memorandum of Understanding, February 12, 2013.

60 CAISO, Energy Imbalance Market Draft Final Proposal, September 23, 2013.

61 Federal Energy Regulatory Commission, 143 FERC ¶ 61,298, Docket No. ER13-1372-000, issued June 28, 2013.

62 SPP, "Western Energy Imbalance Service Market (WEIS)," accessed January 23, 2023.

regional coordination of transmission planning; and (d) development of market prices for energy and ancillary services. These functions are interrelated: the resource adequacy function is enforced through availability in the daily and real-time generator scheduling procedure, and pooled resource adequacy is made more robust through pooled BA operations and generation optimized dispatch; regional transmission planning is more effective than utility-specific transmission planning; and transparent market pricing for energy and ancillary services means that utilities and market participants readily understand the cost of serving their load with generators from another utility, and vice versa.

Like an EIM operator, an RTO is an independent entity that optimizes generator output for the benefit of the entire region, making best use of available transmission capabilities, and settling any net energy excess/shortfalls of members using a public and transparent energy price. The added functionality of an RTO (pooled day-ahead generator commitment and scheduling, resource investment planning, and regional transmission planning) significantly increases the net benefit of an RTO relative to an EIM, even taking into account the potential for higher administrative costs.

RTOs also create a more diverse region across which to calculate total capacity and reserve margin needs. By being able to determine total capacity or reliability requirements across a larger area, the RTO footprint can benefit from the inter-utility supply and demand diversity to reduce the capacity requirements for all customers while ensuring the same level of reliability and resource adequacy. Based on the total RTO capacity requirement, each utility or load-serving entity must then meet their share of total capacity needs and ensure that a minimum level of the capacity is located within their respective locations on the grid due to regional transmission limits. These lower RTO-based capacity requirements can then be met through integrated planning and self-supply (this option is available to vertically integrated utilities in all RTO markets), or by relying on the centralized RTO capacity market (where those exist and are sufficiently robust). The capacity market approach uses a forward competitive auction structure to secure the volume of needed capacity commitments from all qualified sellers, selecting the lowest-cost capacity suppliers first and ensuring transmission constraints are observed.

With transparent wholesale power prices, clear settlement mechanisms, and independent regional transmission administration and planning, RTOs provide a platform to enable competition and maximize use of the transmission system. State regulators in regions that participate in RTOs have the option (but not requirement) to rely more or less heavily on wholesale market price and competition to drive the investment choices of their utilities, public power, and consumers. The transparent prices that an RTO makes available also provide a useful benchmark for utility investments. Should South Carolina wish to pursue more competitive generation or retail supply (as discussed in Sections III and IV of this report), RTO participation provides a useful platform for enabling either or both of those. Such competition provides additional substantial benefits to the state. As discussed further in Section III.E below, an important and valuable feature of RTOs is their regional transmission planning process that is integrated throughout the region (and coordinated with neighboring regions). This serves to further enhance regional markets while lowering costs to consumers and improving reliability, among other benefits.

Since their introduction in the 1990s, RTOs have assisted utilities in successfully lowering the cost of wholesale power. RTOs have grown to include the majority of the United States as shown previously in Figure 8.[63] The hallmark of an RTO is independent coordination of many members across a wide area, often spanning many states. Most RTO customers are in RTOs that span many states. We study two such options in our market simulation modeling: South Carolina (and the portions of Duke Energy in North Carolina) in a new Southeast RTO with the footprint of today's SEEM, and South Carolina (plus Duke Energy in North Carolina) joining PJM. There are three single-state RTOs: California, Texas, and New York. These states are large, they rank first, second, and fourth in population in the United States and due to their size, they can extract much of the benefit of an RTO without the need to coordinate with other states. South Carolina is not as large, thus critically limiting the value a South Carolina-only RTO could provide. Therefore, we did not study a single-state RTO for South Carolina.

The many functions of an RTO provide direct benefits in the form of operational savings and reduced need for installed generation or other resources (or higher reliability from the same sized fleet), with the additional benefit of more efficient regional transmission planning. These three functions complement and augment each other. While most states with an RTO-member utility use a vertically integrated regulation model, an RTO is also a prerequisite for scalable and robust competition in production and supply of electricity for states that choose to pursue such methods. As shown in the next section (Section III), such competitive reforms are themselves a potential source of significant benefits for South Carolina consumers.

RTO Governance and Regulation: Broader regional coordination necessarily entails less autonomy in setting the rules of access for the transmission system (currently proposed separately by each utility under FERC oversight of their respective OATTs) and greater

[63] Not shown are the three Canadian provinces Alberta, Ontario that have their own RTO, and Manitoba, which is a part of MISO.

cooperation and compromise among all members and stakeholders. In an RTO, that compromise is negotiated through its governance.

RTOs, including single-state RTOs, operate high voltage transmission lines that functionally interconnect many states, and administer wholesale transactions in interstate commerce. Therefore they are regulated by the Federal Energy Regulatory Commission (FERC). FERC has issued two landmark orders regarding RTO governance. Order 888 (and its lesser companion order 889), issued in 1996, created the concept of Independent System Operators and a framework for their governance.[64] Order 2000, issued in 1999, did the same for the Regional Transmission Operator concept, an updated take on the ISO.[65] While these orders lay out high-level governance expectations, including board composition and principles for the stakeholder process, nonetheless FERC has been flexible in approving diverse governance structures, as discussed above.

While RTOs have been found to yield large net benefits by leveraging an extensive set of pooling functions, their governance varies both across the RTOs and even within an RTO according to function.[66] For example, transmission cost allocation policies are generally governed by a committee of transmission owning utilities; energy market rules are typically governed by the RTO board, with input from members; day-to-day dispatch authority comes directly from NERC-defined roles via federal legislation.

Two features of RTO governance are prominent: (1) the allocation of OATT "filing rights" and RTO operational activities among the RTO, the RTO Board, its members, and states, which can vary according to policy matters, specific infrastructure investments, and day-to-day decisions; and (2) the voting structure and relative sectoral power of the members within the stakeholder process. Finally, the legal and regulatory environment of RTO-related precedents at FERC and the courts ultimately constrains what RTOs can do within their governance. In addition, the extent to which governance is effective in representing the interests of individual states depends on the uniformity (or diversity) of participating states and market participants. In RTOs with more uniform market participants and participating states (such as SPP, with vertically integrated member states and utilities) governance and consensus building will tend to be easier than in RTOs with a very diverse set of states and market participants.

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[64] Federal Energy Regulatory Commission, "History of OATT Reform," accessed February 11, 2023.

[65] K. Costello and R. Burns, "Regional Transmission Organizations and the Coordination of Regional Electricity Markets: a Review Of FERC Order 2000," The National Regulatory Research Institute, April, 2000.

[66] See Table 8 for a summary of other studies of RTO benefits.

Allocation of authority: Most RTOs have plenary authority over their own rates and policies on file at FERC, known as OATT "filing rights."[67] FERC precedent suggests this is the expected structure of RTO authority, though the RTOs can incorporate stakeholder and state regulatory bodies into formal approval processes that must be passed prior to proceeding with filings to update the prevailing OATT. RTOs also feature an organized stakeholder process to inform or act as a precondition to filing RTO Tariff changes. These stakeholder processes are generally structured with tiers and sector-based voting to produce a final advisory decision, with the RTO holding an important agenda-setting role.

Among RTOs, there are numerous variations on the RTO governance structure, such as:

- In PJM, many rule changes related to energy markets, ancillary services markets, settlements, and various other matters must be approved by members through the stakeholder process in order to be filed under the ordinary process.[68]
- ISO New England is obligated to file policy proposals that meet a minimum stakeholder vote threshold alongside its own corresponding proposal.[69]
- As noted below, states in SPP participate in a governing body that holds an approval role over certain major policy areas such as resource adequacy and transmission cost allocation.

These regional variations partly reflect the historical interests of parties involved in forming the initial RTO and its governance structure. Such parties sought the benefits of the RTO, but were interested to maintain a share of authority over the direction of their RTO's future. For example, SPP and its state regulator constituents sought to reserve to the states a more significant share of authority, and so SPP proposed (and FERC approved) a Regional State Committee with authority over major portions of the SPP Tariff.[70] The Regional State Committee is composed

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[67] That is, they have the right to file changes to their Tariff as the corresponding utility under Section 205 of the Federal Power Act. FERC is required to approve such changes as long as they are just and reasonable. For a detailed accounting of RTO governance, see C. Parent, et al., "Governance Structure and Practices in the FERC Jurisdictional ISOs/RTOs," Exeter Associates, Inc., prepared for New England States Committee on Electricity (NESCOE), February 2021.

[68] Namely, rules that are currently described in the PJM Operating Agreement, over which only the PJM membership holds 205 filing rights.

[69] The minimum vote threshold is 66% sector-weighted vote at the Participants Committee for non-market rule changes and 60% vote for market changes. See Section 3.3 of C. Parent, et al., "Governance Structure and Practices in the FERC Jurisdictional ISOs/RTOs," Exeter Associates, Inc., prepared for New England States Committee on Electricity (NESCOE), February 2021.

[70] The Regional State Committee concept was initially developed by FERC as part of its Standard Market Design Effort. See FERC, White Paper Wholesale Power Market Platform, Docket No. RM01-12-000, April 28, 2003.

entirely of state regulators, and has autonomous rights to file all policy proposals related to resource adequacy, cost allocation related to transmission upgrades, and allocation of transmission congestion surplus (also called "financial transmission rights").[71] See Table 5 below for examples of different ways that RTOs divide their authority among states, stakeholders, and RTO staff and their boards. These regional variations illustrate FERC's flexibility in approving diverse approaches to RTO governance.

RTOs can ultimately authorize funding for investments in transmission (and in some limited cases generation as well).[72] For example, the regional transmission planning process that is common to RTOs results in proposed transmission upgrades (including substation improvements, minor or major upgrades to existing transmission lines, and potentially running new transmission lines). Today, specific transmission investments in RTOs are mainly approved by the RTO board. However, approval processes do vary today, and greater variation may well be possible in the future. While there is no precedent for states to have approval or veto authority over RTO decisions regarding specific transmission investments, and it is unclear whether FERC would approve such a structure, it is nonetheless conceivable.

In traditionally regulated states that are in RTOs, market outcomes (including in a capacity market construct) do not drive investment decisions. States are able to retain a vertically integrated utilities structure and retain full authority to oversee resource investments through IRPs. RTO prices serve to incentivize efficient operations, may result in trades that yield savings for the utility and its customers, and can act as transparent pricing indicators that are useful in the IRP process. In PJM for example, utilities can opt out of the capacity market altogether, removing their supply and demand from any financial interaction with market outcomes.[73] By contrast, in restructured states, RTO market outcomes also incentivize generator (and other resource) investment from private market participants. In that sense, the RTO market rules, especially capacity market rules, ultimately drive investment decisions in restructured states. Those rules are managed through the policymaking process discussed above.

The day-to-day business of the RTO is generally governed by the Tariff and business practice manuals that contain more granular detail. Operations protocols in the dispatch room are often

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[71] Hinton, Justin A., and the Southwest Power Pool Legal Department, The History of the Regional State Committee for the Southwest Power Pool, Inc., SPP, April 2022.

[72] Namely, RTO-authorized "reliability must-run agreements" that fund generators which are needed to maintain system reliability, especially based on local constraints.

[73] The "Fixed Resource Requirement" or FRR option. See PJM, Securing Resources Through the Fixed Resource Requirement, September 23, 2022.

dictated by NERC standards as delegated to Reliability First Corporation (in the case of PJM) or to SERC (in the case of South Carolina and other Southeast utilities), since RTOs generally exercise operational authority through formal NERC roles such as Reliability Coordinator, Balancing Authority, and Transmission Operator. These roles are currently fulfilled in South Carolina by VACAR (administered by Duke) as NERC-designated Reliability Coordinator (RC) and the individual utilities as NERC-designated BA and Transmission Operator (TOP).

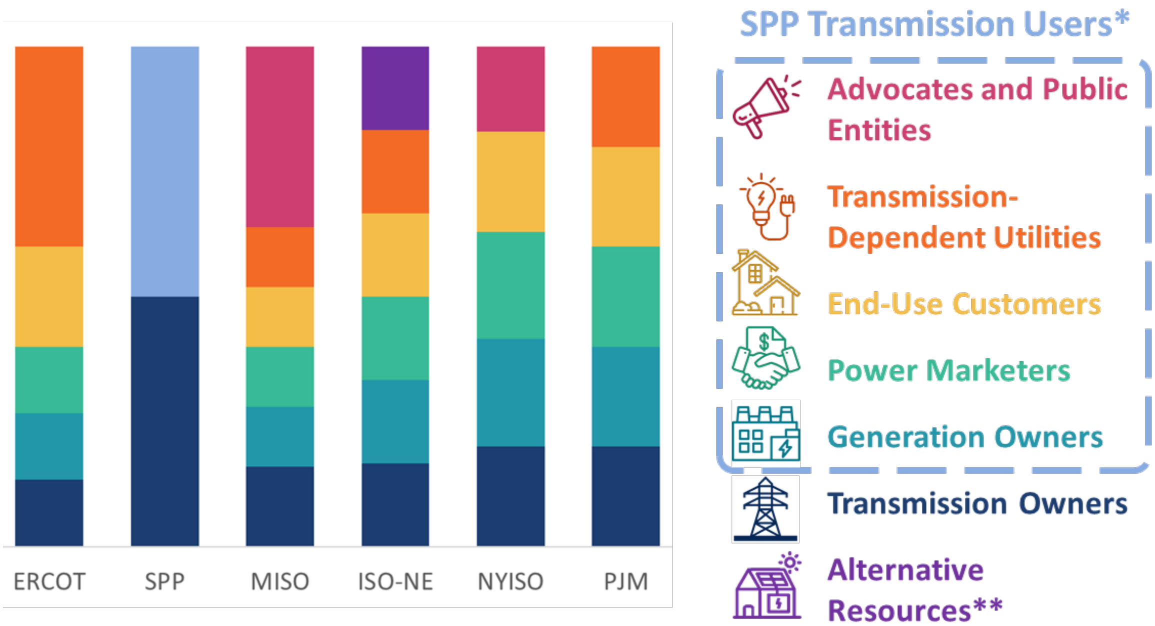
TABLE 5. SOLUTION OPTIONS FOR APPROVER ROLES OF VARIOUS RTO PROTOCOLS

	Status Quo w/out RTO	Examples of RTO Approval Processes Currently In Use	
Resource Adequacy: Resource Mix	*State regulator*	Vertically integrated (with or w/o capacity market): state IRP	Deregulated w/capacity market: RTO Board (as amended by state subsidies)
Resource Adequacy: Installed Reserve Margin Requirement, Accreditation, Allocation of Obligations, etc.	*State regulator*	• States committee authorizes all resource adequacy functions (SPP) • State approval for IRM (NY, CA) and allocation of obligations (CA) • State override (IRM in MISO)	RTO board or staff
Transmission Cost Allocation/Rate Method	*N/A*	States Committee (SPP)	RTO Board or utility-only committee (PJM)
Transmission Rates for a Transmission Owning Utility	*FERC*	Filed by utility, approved by FERC	
Approve Specific Regional Transmission Projects	*State*	States committee (not current implemented in U.S.)	RTO Board, or RTO Board as well as members (SPP)
Allocation of Congestion Surplus ("Financial Transmission Rights," FTRs)	*N/A*	States committee	RTO Board
Generation Interconnection Procedures	*Utility*	Utility specific technical details (widespread) or cost allocation (pending in PJM)	RTO Board
Market and Operational Rules	*N/A*	RTO Board or RTO Board together w/ Members (PJM)	

Stakeholder voting structure: RTO stakeholders consist of transmission owners (i.e., large utilities), market participants (i.e., users of the transmission system), and public representatives. Each RTO hosts a structured stakeholder process that, through voting, can produce advisory policy decisions (informative both to the RTO itself as well as to FERC in its ultimate approval authorities) or in some cases impose a threshold for Tariff revisions. RTOs deploy a sector-weighted vote at the final decision stage, with each member obligated to choose a single sector. Vertically integrated utilities are often assigned the transmission owner sector. Figure 10 illustrates the allocation of votes among the sectors. End-users, transmission-dependent utilities (e.g., municipal and cooperatively owned utilities), and public entities all tend to represent consumers. Representation of this customer group varies somewhat, with greater power in MISO and ERCOT.

Transmission owners represent a unique constituency in the context of RTO voting and governance. Federal “open access” policy has long sought to ensure that all generators and consumers have fair and equal access to the transmission system, and ensure that the transmission owners and their affiliates are not able to privately gain by implementing rules, processes, or rates that intentionally or unintentionally limit competitors’ access. Without an RTO, the primary means of ensuring such access is through FERC oversight that seeks to ensure fair rules of access are incorporated into each transmission owners’ OATT. Under an RTO structure, the transmission owners must work through the same stakeholder processes as other entities and within their own voting share to achieve desired updates to the RTO OATT.

FIGURE 10: RTO STAKEHOLDER VOTING RIGHTS BY SECTOR



Source/Notes: S. Lenhart and D. Fox, [Participatory democracy in dynamic contexts: A review of regional transmission organization governance in the United States](), Energy Research & Social Science, Volume 83, January 2022.

* Transmission users in SPP includes utilities with no more than 500 miles of meshed transmission lines operated at above 60 kV.

** ISO-NE considers renewable generation, distributed generation, and load response as "alternative resources." Other RTOs include these resources in Generation Owner or End-Use Customer segments.

POTENTIAL ADVANTAGES

The potential advantages of joining an RTO are:

- Net benefits that significantly exceed those offered by the status quo and other wholesale market reforms considered here.
- A well-established framework with straightforward legal and technical implementation (most straightforward if pursuing membership in a pre-existing RTO).
- Improved operational tools for reliably and cost-effectively serving load and integrating solar and wind.
- Improved coordination among utilities in South Carolina (and with utilities in neighboring states) in operations and planning.
- Increased ability for consumers, public power, and independent power producers to engage in voluntary transactions at transparent prices and with equal access to the transmission system.

- Provision of regional transmission planning to improve efficiency, reliability, regional integration, and access to lower cost and cleaner resources (discussed further in Section II.F below).
- Can provide a turnkey option for incremental advances in retail choice (if desired by South Carolina policymakers), potentially attracting new industries and customers that can prompt economic development, while also providing more alternatives and potential savings for existing large customers including municipal and cooperative utilities
- Can serve as a platform for competitive generation investments (if desired by South Carolina policymakers).

POTENTIAL DISADVANTAGES

The potential disadvantages of joining an RTO are:

- For functions performed by the RTOs and market rules: requires compromises to achieve consensus with other states, utilities, and other stakeholders of the RTO through the governance process. Functions retained by the utilities, state regulators, and state governments, such as resource planning, local reliability, and state energy policy, remain the sole purview of local authorities.
- Increased scope of functionality and growth in number of market participants increases the complexity of the wholesale market and calls for development of new expertise from state policymakers and staff.
- If a Southeast RTO (rather than joining PJM) is pursued, implementation complexity and timeframes will be increased; implementation efforts will stall if utilities and policymakers in other Southeastern states are not (or do not remain) fully aligned on market design and a sustained commitment to implementation.

RTO IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

Joining PJM: South Carolina could join an existing neighboring RTO (that is, PJM), ideally together with the portions of Duke Energy in North Carolina (as assessed in the present study) or possibly on its own (as described further below). By joining PJM, South Carolina stakeholders would be inheriting the existing market structure and governance that has already been established in PJM. This provides the benefit of experience and speed, but limits the chance to revisit the founding articles of governance and the market's overall design. Of the three major wholesale market reforms, this approach is the fastest and most decisive, and offers the highest net benefits.

PJM is an established RTO and experienced with the orderly integration of new utilities, most recently Eastern Kentucky Power Cooperative in 2013 and, before that, Duke Energy Ohio and Duke Energy Kentucky in 2012. Many vertically integrated utilities are operating within PJM under a state oversight model similar to South Carolina, including those in Virginia, Kentucky, Indiana, and West Virginia. Should South Carolina wish to pursue competitive generation or retail supply, PJM provides a proven platform for enabling either or both of those.

PJM integrations since 2002 have been accomplished in under two years. As shown in Table 6, case studies from 2012 and 2013 show an implementation time of 18 months to join PJM (including regulatory approvals and simultaneous technical integration) and an integration cost on the order of $1 million.[74] An integration effort of comparable or greater cost is also required internal to each integrating utility. As one indicator of a potential low-end estimate for utility-side RTO integration costs, the lowest documented utility-side integration cost we identified is $1 million cited in the EKPC integration (escalated and annualized this amounts to $0.14 million). An indicator of the high-end is illustrated by Dominion's 2004 integration to PJM—escalated to $2022 this equates to $37 million in one-time costs, or approximately $4 million per year if annualized over 15 years.[75] We therefore use a range of $0 - $4 million to represent approximate utility-side RTO integration costs.

Integration tasks consist of communicating technical details of each transmission and generation facility to PJM so that detailed models of such facilities can be expanding to include the broader footprint. New business process are implemented at the utility for ongoing communication of operational details, and in some cases new hardware is added for monitoring transmission lines. Demand response programs may need to be altered in order to participate in the PJM capacity market and energy markets.

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[74] Federal Energy Regulatory Commission, 139 FERC ¶ 61,068, Docket No. ER12-91-000, ER-12-91-002, ER12-92-002, Order 462, Page 9, issued April 24, 2012; PJM and EKPC, "Agreement to Implement Expansion of PJM Region for East Kentucky Power Cooperative," January 9, 2012. Included in "East Kentucky Power Cooperative, Inc. submits Request for Waiver to Participate in PJM Reliability Pricing Model Auctions under ER13-414," filed November 15, 2012.

[75] Federal Energy Regulatory Commission, Docket No. ER04-829-000, Page 17, May 11, 2004; "Joint Application to Establish PJM South"; Kentucky Public Service Commission, Case No. 2012-00169, Exhibit 4, Page 11, May 3, 2012; "The Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, L.L.C."; U.S. Bureau of Labor Statistics, CPI for All Urban Consumers, seasonally adjusted.

TABLE 6. IMPLEMENTATION CASE STUDIES FOR INTEGRATION WITH PJM

	Duke Energy Ohio/Kentucky Integration to PJM	Eastern Kentucky Power Cooperative Integration to PJM
Integration cost to the utility	Estimated at $1 million[76] PJM cost, together with a comparable cost to the utility	Estimated at $750,000[77] PJM cost, together with a comparable cost to the utility
State and FERC approval timeline	About two years: • State: initial KY PSC approval request filed May 20, 2010; final approval on Dec. 22, 2010[78] • FERC: Duke indication of intent to switch from MISO to PJM on June 25, 2010; formal request to join PJM filed Oct. 14, 2011.[79] FERC approval on April 24, 2012 (retroactively effective Jan. 1, 2012).[80]	About one year: • State: initial request on May 3, 2012, final approval on Dec. 20, 2012[81] • FERC: initial request on March 28, 2013, FERC approval on May 22, 2013[82]
Technical integration timeline	One and a half years: • Duke signed integration agreement with PJM on June 25, 2010, followed by high-level planning[83] • Integration went live on Jan. 1, 2012	One and a half years: • EKPC signed integration agreement with PJM on Jan. 9, 2012, followed by high-level planning[84] • Integration went live on June 1, 2013

State-level regulatory approvals are sometimes required when a utility joins an RTO. While new state laws or regulations are not required for a utility to join an RTO, some states do pass laws to compel utilities to join an RTO, together with regulations that describe the minimum requirements for an organization to be considered an RTO from the state's perspective. South Carolina could look to three examples of such law and regulation, each of which comes from states with vertically integrated utility structure that is broadly similar to South Carolina:

- Virginia state code Title 56, Chapter 23, section 579, "Regional transmission entities," which describes the criteria for meeting the state obligation to join an RTO. The corresponding

[76] Federal Energy Regulatory Commission, 139 FERC ¶ 61,068, Docket No. ER12-91-000, ER-12-91-002, ER12-92-002, Order 462, Page 9, issued April 24, 2012.

[77] PJM and EKPC, "Agreement to Implement Expansion of PJM Region for East Kentucky Power Cooperative," January 9, 2012. Included in "East Kentucky Power Cooperative, Inc. submits Request for Waiver to Participate in PJM Reliability Pricing Model Auctions under ER13-414," filed November 15, 2012.

[78] Kentucky Public Service Commission, Case No. 2010-00203 Received, May 20, 2010. Kentucky Public Service Commission, Case No. 2010-00203 Order, December 22, 2010.

[79] "Duke Energy Ohio, Inc et al submits the first step of their proposed move from the Midwest ISO to PJM Interconnection under ER10-1562," June 25, 2010; Federal Energy Regulatory Commission, 362 FERC ¶ 61,068, Docket No. ER12-91-000, October 14, 2011

[81] Kentucky Public Service Commission, Case No. 2012-00169, May 3, 2012; Kentucky Public Service Commission, Case No. 2012-00169, December 20, 2012.

[82] "East Kentucky Power Cooperative, Inc. submits tariff filing per 35.13(a)(2)(iii: Revisions to the PJM OATT, OA & RAA re EKPC Integration," March 28, 2013, Docket ER13-1177-000; "Letter order accepting East Kentucky Power

regulations in Virginia state Administrative Code Title 20, Chapter 320, "Regulations Governing Transfer of Transmission Assets to Regional Transmission Entities" further enumerates the requirements for an RTO in Virginia.

- Colorado Senate Bill 21-072 and Nevada Senate Bill 448 both establish relevant authorities, timelines, and evaluation criteria for regional market integration.[85]

RTOs' ongoing operating costs are funded by consumers. These costs are at least partly offset by cost savings associated with the transfer of certain operational and planning functionality from the utility to the RTO. According to FERC data from 2018, RTO charges have ranged from $0.35/MWh to $1.60/MWh.[86] In 2021, the PJM rate stood at $0.40/MWh.[87] Conservatively neglecting offsetting administrative savings within South Carolina utilities, a rate of $0.40/MWh in the context of South Carolina in 2030 amounts to $36 million per year.[88] In our assessment of net benefits of the RTO market reforms, we use this value to estimate PJM's approximate annual administrative cost to South Carolina customers.[89] This is a conservative estimate in the PJM context, since the presence of South Carolina would bring economies of scale to PJM that would tend to put downward pressure on the administrative cost per MWh.

PJM identifies higher-voltage regional transmission upgrades that are necessary for reliability. When member transmission owning utilities build such upgrades (with approval from the state regulator), half the cost is allocated across the entire RTO. If South Carolina utilities joined PJM

Cooperative, Inc's 3/28/13 submittal of a joint filing in connection with EKPC's integration into PJM," Docket ER13-1177-000, May 22, 2013.

82 "East Kentucky Power Cooperative, Inc. submits tariff filing per 35.13(a)(2)(iii: Revisions to the PJM OATT, OA & RAA re EKPC Integration," March 28, 2013, Docket ER13-1177-000; "Letter order accepting East Kentucky Power Cooperative, Inc's 3/28/13 submittal of a joint filing in connection with EKPC's integration into PJM," Docket ER13-1177-000, May 22, 2013.

83 Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc., Initial Filing before the Federal Energy Regulatory Commission (FERC), June 25, 2010.

84 "Agreement to Implement Expansion of PJM Region for East Kentucky Power Cooperative." Included in "Duke Energy Ohio, Inc et al submits the first step of their proposed move from the Midwest ISO to PJM Interconnection under ER10-1562," June 25, 2010.

85 General Assembly of the State of Colorado, Colorado Senate Bill 21-072, 2021 Regular Session, signed June 24, 2021; Nevada Legislature, Nevada Senate Bill 448, 81st Session, (2021), signed June 10, 2021.

86 Federal Energy Regulatory Commission, "Common Metrics Staff Report, 2014 to 2018," Docket No. AD19-16-000, Page 44, July 2021.

87 PJM, "Administrative Rate Proposal," slide 13, September 29, 2021.

88 In our 2030 simulation scenario, South Carolina has a total of 90,370 GWh of annual load.

89 The annualized value of the approximately $1 million one-time cost that PJM charges to integrate a new utility does not significantly increase the $36 million result.

(as opposed to partnering with PJM in a non-RTO pooling arrangement, as described in the discussion of "Implementation Considerations for South Carolina" in Section II.D), customers in other PJM states would ultimately contribute to funding these upgrades, while customers in South Carolina would enjoy the reliability and operational benefits. On the other hand, the South Carolina utilities would be allocated such costs from upgrades in other states. A PJM tool for estimating such costs based on existing and planned regional transmission upgrades indicates that South Carolina's share could be approximately $28 million annually in 2030.[90] This would initially result in a net increase in transmission costs to South Carolina, prior to construction of new regional transmission facilities. If such costs were included in the net benefit calculation, the result would show a net benefit of joining PJM that is lower—using the $28 million estimate, the net benefit would be between $253 – $334 million annually. However, as new regional transmission facilities were built, net benefits could rise or fall according to the specific regional transmission facilities built, their degree of improvement of operational efficiency in South Carolina, their cost, and the extent to which that cost were allocated out of state.

If it were not practical to coordinate with the North Carolina utilities to join PJM together in a common strategy and timeline, some or all of the South Carolina utilities could join PJM individually and at different times. Depending on the sequence of other utilities' integration plans, the state may initially (or permanently) join as a non-contiguous part of PJM, with a contract-path transmission link but limited PJM integration to intervening transmission capability.[91] Transfers between South Carolina and PJM through North Carolina (or potentially other regions) would be accomplished using today's Tariff-based wheeling transmission scheduling protocols. The RTO would then incorporate those transmission schedules into its dispatch and other processes. Establishing firm transmission from South Carolina to PJM would likely be necessary, especially for robust pooling of resource adequacy and other planning. The more limited RTO participation of South Carolina utilities combined with the limited scope of a contract-path

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90 To capture this cost, we used PJM's Transmission Cost Information Center (TCIC) tool to estimate the cost that would be allocated in 2030 to South Carolina plus Duke's North Carolina utilities based on PJM coincident peak-load ratio share. This was then allocated to South Carolina based on its estimated share of coincident peak values. Coincident peak load values were calculated using projected hourly load data for Balancing Authorities in the Carolinas and PJM, as well as the South Carolina share of the Carolinas utilities. See TCIC tool at PJM, "Project Status and Cost Allocation", accessed April 7, 2023.

91 It is theoretically (but likely not practically possible) that Duke's South Carolina territories could join PJM without the North Carolina portion, as this would require that each Duke utility to reconfigure their internally-pooled operations that currently span the two states, which would introduce operational inefficiencies and also require extensive new metering equipment.

transmission link would reduce the achieved benefits, but may still have the effect of spurring more neighboring utilities and state regulators to examine the potential RTO benefits.

This contract-path transmission approach to RTO participation and other pooling arrangements has been used before: when Commonwealth Edison joined PJM in 2004, and in the initial years of CAISO's WEIM, when PacifiCorp West and Puget Sound Energy were non-contiguous.[92] Over time the regional scope of each regional market has expanded, which has integrated the initial member more robustly as more utilities have joined the markets.

Starting a Southeast RTO. Formation of a new multi-state Southeast RTO would allow South Carolina's state regulators, utilities, and other stakeholders to join with other Southeastern states in establishing the independent entity, developing its governance structure, and designing its market rules to fit the needs of the broader region. On the other hand, this would be no small task—it would require consensus across many states that would likely take years to obtain. All of today's RTOs grew out of predecessor organizations that had been coordinating utility operations for decades, thus facilitating consensus-building for the launch of an RTO.[93] In order to tackle the start-up effort in a more manageable way, the utilities might initially focus on a simpler EIM model, and then transition to a more full-featured RTO over time, as was the case for most of the established RTOS and has been playing out in the Western EIM over the last 12 years. Many of today's RTOs launched with much-reduced functionality that focused on real-time trades (sometimes without even a real-time energy market at all—a "day one RTO").

A Southeast RTO with the footprint of SEEM (as studied in the present report) would cover 10 states (the Carolinas, Tennessee, Kentucky, Georgia, Alabama, Florida, Mississippi, Missouri, and Oklahoma). In addition to achieving consent from each utility, each state would have to: (a) permit their utilities joining an RTO; and (b) accept the governance structure of the RTO. Such an effort could reasonably be initiated with a commitment from several states as well as the region's large utilities (e.g., Duke, TVA, and Southern Company).

92 Yan Lin, et al., Impact assessment of expanding PJM market area by incorporating incremental loss model, IEEE Power Engineering Society General Meeting, 2005, Pages 326–331 Vol. 1, June 16, 2005.

93 ISO New England had been NEPOOL, founded in 1971; NYISO had been the New York Power Pool, 1969; PJM was founded in 1927; MISO grew out of discussions among the members of the Mid-American Interpool Network (MAIN, founded 1964 and merged with MISO in 2000) and the East Central Area Reliability Council (ECAR, 1967), and quickly took over the operations of the Midcontinent Area Power Pool (MAPP, formed in 1965); ERCOT was founded in 1970; SPP was founded in 1941; and CAISO grew out of the California Power Pool, 1961.

The process of creating an RTO has historically taken several years of stakeholder consensus building before administrative operations can start, followed by a further multiyear effort for establishing energy market operations. For example, the utilities that would go on to form MISO started discussions in early 1996, made their initial FERC filing in 1998, and started operations as an RTO in 2001.[94] Their initial role was limited to administering the common tariff and regional transmission service, and it was not until 2005 that they launched their energy market. SPP's initial RTO filing was made in 2000, followed by a second in 2003.[95] They launched in 2004, began a real-time EIM-style energy market in 2007, and implemented full RTO market functionality in 2014. Notwithstanding this record, it is possible that stakeholders in the Southeast could move more quickly towards consensus than the MISO and SPP processes suggest. Moreover, implementation time could proceed more quickly now that RTOs have extensive experience building and running the requisite infrastructure and processes, which the Southeast RTO could leverage by subcontracting with an existing RTO (such as SPP, MISO, or PJM) to host the operational infrastructure (thereby also lowering cost). This "subcontracting RTO operations" approach was contemplated by the Mountain West utilities in Colorado and Wyoming, when they were considering creating the Mountain West RTO (as discussed earlier).

An indication of the potential range of administrative costs allocated to South Carolina from a new Southeast RTO can be derived from costs from other present-day RTOs. As the lowest-cost RTO, PJM's administrative cost of $0.40/MWh can indicate an approximate low end of the range, while SPP's cost of approximately $0.58/MWh can indicate a high end (CAISO and ISO New England rates are higher still, but SPP labor costs better reflect conditions in the Southeast).[96] Using South Carolina's modeled 2030 load of 90,320 GWh, these scenarios indicate an approximate range of $36 – $52 million annually.

RTO administrative charges often include recovery of capital costs for prior investments. If a new Southeast RTO partners with an existing RTO to leverage existing infrastructure, then the current RTO administrative rates could be indicative of the low end of costs for the Southeast. Otherwise, investments needed to start a new RTO could contribute to additional administrative costs. An indicator of the high end of such cost can be drawn from the implementation of a nodal market

94 Midwest ISO, "Midwest ISO Filing," Docket No. ER98-1438-000, January 15, 1998; "MISO History," accessed February 13, 2023.

95 SPP, "Southwest Power Pool Inc submits its RTO proposal," October 13, 2000, Docket No. RT01-34-000; FERC, "SPP," accessed February 13, 2023.

96 Federal Energy Regulatory Commission, "Common Metrics Staff Report, 2014 to 2018", Docket No. AD19-16-000, Page 44, July 2021; PJM, "Administrative Rate Proposal," slide 13, September 29, 2021.

in ERCOT. ERCOT's project was associated with unexpected cost overruns and delays, ultimately costing $509 million.[97] Annualized over 15 years at a rate of 8%, this amounts to an added annual cost of $77 million allocated across the entire Southeast RTO footprint, with South Carolina's share calculated at $10 million per year.[98] To the high end of the administrative cost range, we also add the $4 million cost associated with utility-side investments described in the PJM analysis above.

F. Enhanced Regional Transmission Planning

DESCRIPTION AND RELEVANT CASE STUDIES

Regional transmission planning refers to development of transmission that spans or otherwise affects multiple utilities. Regional transmission investments serve to integrate operations across multiple utilities to multiply the value of pooled operations and facilitate pooled resource adequacy. Regional transmission planning can provide cost savings from congestion relief, more effectively and efficiently serve growing load, improve reliability and resilience, and provide access to low-cost renewables.

Today, almost all investments in regional transmission are a result of RTO planning processes, one of the core functions of an RTO. The RTO's pooling of operations is a natural complement to regional transmission planning, and vice versa. If utilities mainly operate within their own boundaries, and trade across their borders is moderate and limited by frictions, it is harder to justify transmission upgrades between utilities; likewise, if there is minimal transmission connecting utilities, there is less ability to trade.

In parts of the country that (like South Carolina) are outside RTO areas, transmission upgrades are mainly planned by each utility and upgrades prompted by regional transmission planning processes are less common. Such regional transmission planning is facilitated by transmission planning entities and agreements, some of which operate according to FERC regulation under Order 890 and Order 1000. These orders are intended to ensure that interstate transmission services are provided at just and reasonable rates and on a basis that is not unduly discriminatory or preferential, consistent with FERC's duty under the Federal Power Act. Dominion Energy South Carolina and Santee Cooper participate in the FERC-regulated South Carolina Regional

97 Lester, Todd K., Clay Ryals, Dan Stathos, and Jared Jordan, "Evaluation of ERCOT's Texas Nodal Market Implementation Project (TNMIP)", Navigant Consulting, August 30, 2012.

98 South Carolina's share of the Southeast's coincident peak is 13%. See Appendix A, page A-2.

Transmission Planning group, while Duke participates in Southeastern Regional Transmission Planning).[99] These groups are helpful for coordinating planning studies among member utilities and confirming their systems are expected to operate reliably, even as they evolve. In some cases, the coordinated studies identify upgrades that utilities must perform on their own systems, or even inter-utility upgrades. However, most regional planning cycles in non-RTO areas across the United States do not result in any transmission upgrades between two utilities, let alone regional transmission upgrades that are selected for cost allocation through the Order 890 and Order 1000 processes.[100]

Other transmission coordination groups exist outside the construct of FERC Orders 890 and 1000. For example, the Carolinas Transmission Coordination Agreement (CTCA), the SERC Long Term Study Group (LTSG), the Eastern Interconnection Planning Collaborative (EIPC), and the Eastern Interconnection Reliability Assessment Group (ERAG). These are effective at identifying reliability violations and similar concerns, including at the regional and sub-regional level, but they have not resulted in major regional upgrades spanning multiple utilities of the type that yield large cost savings or facilitate significant shifts in the resource mix.

Improved regional transmission planning offers the opportunity to significantly reduce costs for consumers through more efficient and reliable operation and access to resources. Brattle has recommended that policymakers pursue several enhancements to the regional transmission planning process, including as applied both inside and outside RTOs in the United States.[101] These recommendations encourage multi-value assessment, scenario-based assessment, and improved cost allocation. The multi-value approach ensures that processes explicitly account for all values of transmission, including reliability, reduced congestion, and achievement of policy goals. We

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99 Southeastern Regional Transmission Planning (SRTP), "Southeastern Regional Transmission Planning," accessed February 13, 2023.

100 For example, the 75-page WestConnect regional transmission plan report concludes by stating: "*Based on the findings from the 2020–21 planning cycle analysis performed for reliability, economic, and public policy transmission needs as described in this report, no regional transmission needs were identified in the 2020–21 assessment.*" WestConnect, "WestConnect 2020–21 Regional Transmission Planning Cycle," December 15, 2021. Further, the Sustainable FERC Project, Natural Resources Defense Council, the Sierra Club, et al., state that "*regional transmission planning in non-RTO regions is essentially nonexistent*" and "*only two regional transmission projects have been identified in the SERTP planning process since 2014*." Public Interest Organizations, "Comments Of Public Interest Organizations in RE: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," October 12, 2021, Docket No. RM21-17-000.

101 J. Pfeifenberger et al., A Roadmap to Improved Interregional Transmission Planning, The Brattle Group, November 30, 2021.

provide the following suggestions for state policymakers that can influence regional transmission planning processes:

- Encourage use of multi-value benefit analysis to assess the extent to which certain regional transmission investments can reduce overall customer costs (e.g., by offering a more cost-effective transmission solution than individual utility-planned projects or by reducing generation-related costs);
- Consider whether multi-state regional planning authorities are necessary for identifying policy-related needs for increased transfer capability between states and regions in the absence of a federal planning process;
- Engage regional planning authorities to modify the approach to analyzing regional transmission needs and transmission-related benefits that reduce overall customer costs;
- Develop scenarios for regions to consider in regional planning efforts, including with future resource mixes that achieve existing state policy mandates and plausible new future policy goals; and
- Propose and support innovative, flexible, and portfolio-based cost allocation for interregional public policy projects.

The above recommendations would need to be pursued in coordination with other regional stakeholders and federal policymakers, since the regional planning process is regulated by FERC. The most significant action that South Carolina policymakers can take to achieve cost savings from improved regional transmission planning is to require South Carolina utilities to more actively coordinate transmission planning or to join an RTO. RTOs already have in place robust regional transmission planning processes that yield major inter-utility investments to improve congestion, reliability, and achieve state policy goals. RTOs thus provide a ready template that would represent a step forward for South Carolina, whether joining PJM or forming a new Southeast RTO. Table 7 provides examples of multi-value regional transmission planning from the RTO processes.

TABLE 7. EXAMPLES OF EXPANDED TRANSMISSION BENEFITS ANALYSIS TO ASSESS THE EXTENT TO WHICH TRANSMISSION PROJECTS CAN REDUCE TOTAL CUSTOMER COSTS

SPP 2016 RCAR, 2013 MTF	MISO 2011 MVP ANALYSIS	CAISO 2007 TEAM ANALYSIS OF DPV2 PROJECT	NYISO 2015 PPTN STUDY OF AC UPGRADES
Quantified			
Production cost savings: value of reduced emissions reduced AS costs	Production cost savings	Production cost savings and reduced energy prices from both a societal and customer perspective	Production cost savings
Avoided transmission project costs	Reduced operating reserves	Mitigation of market power	Capacity resource cost savings
Reduced transmission losses capacity benefit energy cost benefit	Reduced planning reserves	Insurance value for high impact low-probability events	Reduced refurbishment costs for aging transmission
Lower transmission outage costs	Reduced transmission losses	Capacity benefits due to reduced generation investment costs	Reduced costs of achieving renewable & climate goals
Value of reliability projects	Reduced renewable generation	Operational benefits (RM)	
Value of meeting policy goals	Reduced future transmission	Reduced transmission losses*	
Increased wheeling revenues	Investment Costs	Emissions benefit	
Not Quantified			
Reduced cost of extreme events	Enhanced generation policy flexibility	Facilitation of the retirement of aging power plants	Protection against extreme market conditions
Reduced reserve margin	Increased system robustness	Encouraging fuel diversity	Increased competition and liquidity
Reduced loss of load probability	Decreased nat. gas price risk	Improved reserve sharing	Storm hardening and resilience
Increased competition/liquidity	Decreased CO2 emissions	Increased voltage support	Expandability benefits
Increased congestion hedging	Decreased wind volatility		
Mitigation of uncertainty	Increased local investment and job creation		
Reduced plant cycling costs			
Societal economic benefits			

Source/Notes: J. Pfeifenberger et al., A Roadmap to Improved Interregional Transmission Planning, The Brattle Group, November 30, 2021.

POTENTIAL ADVANTAGES

Whether improved regional transmission planning is pursued through an RTO or other means, the considerations are largely the same. The main benefit is an improved ability to reduce costs, including through facilitating the exchange power with neighboring utilities, which yields these advantages:

- Identification of more cost-effective regional transmission solutions.
- Improved transmission system reliability.

- Improved resilience in the face of low-probability events.
- Cost savings from reduced transmission congestion and improved trading with neighbors.
- Ability to interconnect lower-cost renewables inside and outside each the utility's footprint.
- A potential reduction in installed reserve margin requirement needed to meet the same reliability target by being more strongly interconnected to a larger geographic market with higher load and resource diversity.

POTENTIAL DISADVANTAGES

- Disagreements over cost allocation for regional transmission projects (regional sharing of costs may create the impression that some regions are winners or losers).
- State regulators will tend to have more jurisdictional influence over utility-specific transmission projects than regionally planned transmission.

G. Benefit-Cost Assessment of Potential Wholesale Market Reforms

We simulated a 2030 scenario of the South Carolina and regional wholesale power markets to quantify the estimated future benefit to South Carolina consumers from each wholesale market reform in two broad domains: (1) **operational cost savings** (i.e., savings from improved generation dispatch and trade, applicable to the JDA, EIM, and RTO scenarios), and (2) **investment savings** that arise from reduced capacity requirements due to load diversity benefits realized from pooling over a larger footprint. Additionally we benchmarked our operational model to historical data and benchmarked our overall results to a literature review of the benefits of wholesale market reforms in other jurisdictions, summarized below.

We note that our estimates of net benefits may be conservatively low due to the following modeling approaches and assumptions:

- The model does not account for day-ahead forecast error of renewable generation and load. The model applies the same hourly load and renewable generation in the day-ahead unit commitment and dispatch optimization, as in the real-time optimization. Therefore, our simulations do not capture the benefit regional wholesale markets provide by optimizing real-time dispatch to manage imbalances.
- The modeling results reflect hourly granularity with full foresight of real-time market conditions (i.e. without uncertainty). This will understate the intra-hour, real-time benefits of

a JDA, EIM, and RTO and result in understated total net benefits, more so in the case of an RTO, relative to the Status Quo.

- The simulation does not include transmission outages, which understates the efficiency gains achieved in a regional market. The optimization performed in a wholesale market can lower the cost of re-dispatching the system during transmission outages, by drawing on resources from across the footprint.
- The model utilizes natural gas fuel price forecasts provided by the Advisory Board utility members. Forecasts apply average price volatility and average geographic differences in prices, which does not capture periods of extreme volatility and large regional fluctuations in gas prices, such as those experienced during severe winter weather. Modeling natural gas price volatility in line with these events would increase the operational benefits of all regional market options studied by creating larger gains from trading power across the market footprint.
- 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 Status Quo, including SEEM, in 2030 is significantly more efficient than SEEM has been since its launch and assumes that SEEM would develop in the future. However, if the SEEM transaction volumes remain closer to historical volumes, the incremental benefits from the other market reform options studied (the JDA, EIM, and two RTO options) would be greater than estimated (see Appendix C).
- 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 were to build new transmission infrastructure with the approval of the South Carolina PSC, this would increase the trading capabilities between the South Carolina BAAs or with neighboring BAAs and the benefits of joining a regional market would increase.
- Our analyses of administrative and implementation costs are based on experience elsewhere with few examples of publically disclosed costs in some cases. If actual administrative and implementation costs are lower than these past studies, net benefits would be greater.

BENEFITS REALIZED FROM WHOLESALE MARKET REFORMS IN OTHER JURISDICTIONS

Since the launch of organized regional wholesale power markets in the 1990s, many studies have been performed to quantify their benefits. Each focused on a different geographic area, or covered a different set of the potential benefits of an RTO, but they generally all included operational cost savings usually referred to as "production cost savings." These are the savings in fuel and maintenance costs when the scheduling and dispatch of a fleet of generators is optimized across a very wide area, rather than being optimized separately within each utility. Forward-looking production cost estimates often are used by utilities that are considering joining an RTO or EIM and seek to understand the net benefits to their customers. We have performed several studies like this recently, as summarized in Table 8.

TABLE 8. STUDIES OF POTENTIAL RTO AND EIM EXPANSIONS

Name	Study Region	Year	Estimated Cost Savings
Western Energy Imbalance Service and SPP Western RTO[102]	SPP WEIS vs. RTO expansion in the Western United States	2020	Production cost savings of around 4% for new members joining the WEIS or SPP RTO.
WEIM vs. WEIS benefits study for Black Hills Energy, CSU, PRPA and PSCO[103]	WEIM vs. WEIS expansion in Colorado	2020	Production cost savings range from 0.3% to 3.6% for new members joining the WEIM or WEIS.
Mountain West Transmission Group[104]	RTO market formation in Colorado and Wyoming	2016	Production cost savings of 5%–9%. Did not study other benefits, such as improved long-term investment decisions, renewable integration, or reliability
California SB350[105]	RTO market formation in western U.S.	2016	\$1–\$1.5 billion per year in production and investment cost savings for California ratepayers from participation in a Western-wide RTO market
Basin/WAPA/ Heartlands[106]	Benefit from Joining SPP or MISO	2013	Production cost savings of 3%–4% Did not study other benefits, such as improved long-term investment decisions, renewable integration, or reliability

Source/Notes: See footnotes.

Retrospective studies to evaluate the cost savings offered by EIMs and RTOs with the benefit of hindsight also have been performed. The RTOs periodically conduct such studies, comparing actual costs (for power production, generation investment, and transmission investment) with estimated costs that would have been in the absence of the RTO. Such backwards-looking studies often measure more types of benefits, not only those from (operational) production cost savings. These are summarized in Table 9.

[102] J. Tsoukalis, et al., Western Energy Imbalance Service and SPP Western RTO Participation Benefits, The Brattle Group, December 2, 2020.

[103] J. Chang, et al., Joint Dispatch Agreement Energy Imbalance Market Participation Benefits Study, The Brattle Group, January 14, 2020.

[104] J. Chang, et al., Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint, The Brattle Group, December 1, 2016.

[105] The Brattle Group, Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California, prepared for California ISO (CAISO), July 8, 2016.

[106] M. Celebi, et al., Integrated System Nodal Study: Costs and Revenues of ISO Membership, The Brattle Group, March 8, 2013.

TABLE 9. STUDIES OF COST SAVINGS FROM EXISTING WHOLESALE MARKETS

Region	Study	Year	Estimated Cost Savings
MISO[107]	2021 Value Proposition Study	2021	• $3.0–$3.8 billion annually
Western EIM[108]	Q4 Value Study	2022	• $739 million in savings in 2021 • $1.4 billion in savings in 2022 • $3.4 billion cumulative cost savings since 2014
PJM[109]	PJM Value Proposition	2019	• $3.2–$4.0 billion annually
SPP[110]	2021 Member Value Study	2021	• $2.1 billion annually
SPP, Western Energy Imbalance Service (WEIS)[111]	2022 Member Value Study	2022	• $31.7 million in net benefits in 2022 • $61.2 million in cumulative net benefits since 2021
PJM (Dominion Virginia Service Territory)[112]	2015 PUC filing on Benefits of PJM Membership	2015	• $109 million of production cost savings in 2014 • $75 million of production cost savings in 2013 • Cumulative 2005–2015 benefits filed with NC PUC, but not made public • Did not study other benefits, such as improved long-term investment decisions, renewable integration, or reliability

Source/Notes: See footnotes.

The extent of net benefits can vary for different utilities and geographies. Important factors include the efficiency and resource mix of each utility's generation fleet, the level of renewable resource deployment in the area, and the hourly and seasonal trends for customer demand in each utility (for example, a mix of summer and winter peaking utilities). For example, if electricity demand is low at one utility at the same time that it is high at another, significant benefits can accrue to both utilities through regional sharing of generation output to meet combined electricity consumption. The cost savings for RTOs vary by region because these factors are

[107] MISO, "2021 MISO Value Proposition," March 9, 2022.

[108] California ISO, "Western EIM Benefits Report: Fourth Quarter 2022", January 31, 2023.

[109] PJM, PJM Value Proposition accessed February 13, 2023.

[110] SPP, 2021 Member Value Study, April 6, 2022.

[111] SPP, Benefit of the Market Western Energy Imbalance Service (WEIS), March 27, 2023.

[112] Direct Testimony of Alan Meekins on Behalf of Virginia Electric and Power Company, Before the State Corporation Commission of Virginia, Case No. PUE-2015-00022, February 27, 2015; and Direct Testimony of Alan Meekins on Behalf of Virginia Electric and Power Company, Before the State Corporation Commission of Virginia, Case No. PUE-2014-00033, May 2, 2014.

different from place to place, as seen in the differences in estimated cost savings shown above in Table 9.

QUANTITATIVE MODELING OF BENEFITS OF WHOLESALE MARKET REFORMS IN SOUTH CAROLINA

The dispatch of generators incurs major fuel and maintenance costs, and optimization of generator scheduling and dispatch across wide areas can produce significant operational cost savings, together with better utilization of existing transmission infrastructure for trades between utilities and other market participants. We studied four wholesale market reforms that achieve such coordination—a Carolina JDA, a Southeast EIM and RTO that cover the current SEEM footprint, and an RTO case in which the Carolina utilities join PJM—each described in detail below. Meanwhile, we calculate the savings in capital cost from regional coordination of system planning in generation investment. Two of the wholesale market reforms also achieve these savings, as detailed below.

We performed quantitative assessments of **operational cost savings** detailed using a simulation of South Carolina and regional electric grid operations for 2030, spanning from New Jersey to Illinois, Missouri, and Tennessee, and from Alabama to Florida, as described in detail in Appendix B and Appendix C. We additionally calculated estimated **investment savings** by analyzing the diversity of hourly loads between the status quo and the two RTO scenarios described below and in detail in Appendix A.

As discussed further below, the model omits some details that would tend to increase the value of regional coordination, and so these results are conservative. Moreover, while the model includes projected deployments of wind, solar, and storage through 2030, these results would tend to be higher as such shares of wind and solar continue to grow beyond the study period, and so benefits would be expected to grow in time.

DESCRIPTION OF MODELED SCENARIOS

The Carolinas **Joint Dispatch Agreement (JDA)** scenario combines the real-time operations of Dominion Energy South Carolina, Santee Cooper, and the Duke Energy utilities in both North and South Carolina (including Duke Energy Carolinas and Duke Progress Energy). The study assumes each utility retains the separate Balancing Authority roles as assigned in the Status Quo. The South Carolina municipal utilities and Central Electric Cooperative are accounted for within the four South Carolina Balancing Authorities. Following typical JDA operations, each utility schedules their own load in the day-ahead cycle (including high-friction bilateral trades where the advantage exceeds the hurdle rate), while real-time operations feature almost seamless cross-utility optimization (except a small hurdle rate representing the simplistic representation of available transmission in the JDA construct).

The Southeast **Energy Imbalance Market (EIM)** scenario combines the real-time operations of the South Carolina utilities (including the North Carolina portions of Duke Energy) with those of other utilities in SEEM: the Tennessee Valley Authority (TVA), the Southern Company utilities, Louisville Gas and Electric/Kentucky Utilities (LGE/KU), Associated Electric Cooperative, Inc., Duke Energy Florida, Tampa Electric Company, PowerSouth, Seminole Electric Cooperative, and JEA. Like the JDA case, the existing configuration of Balancing Authority roles is not changed. Unlike the JDA case, the EIM has the ability to turn on fast-start gas generators in real-time, and fully utilizes inter-utility transmission via a more sophisticated optimization method.

The **Southeast RTO** scenario models both operational cost savings and investment savings. The model simulates pooled day-ahead scheduling of generators followed by pooled real-time dispatch, as well as consolidated Balancing Authority operations that pool reserves. Investment savings assume pooled resource adequacy across the entire footprint (without consideration of locational constraints). The Southeast RTO uses the same SEEM footprint as the EIM scenario.

The **PJM RTO** scenario uses the full RTO pooling functionality (the same as the Southeast RTO scenario above). Its footprint combines PJM, North Carolina, and South Carolina.

Table 10 below is a summary of the regions contained in each of the modeled scenarios while Figure 11 shows the maps of each modeled footprint.

TABLE 10. SUMMARY OF SCENARIO DEFINITIONS

Region	Totals for South Carolina	JDA	EIM	SERTO	PJMRTO
Dominion SC	X	X	X	X	X
Santee Cooper	X	X	X	X	X
Duke (SC portions)	X	X	X	X	X
Duke (NC portions)		X	X	X	X
Rest of Southeast *			X	X	
PJM					X

Source/Notes: *The EIM and SERTO footprints are identical to the SEEM footprint, including (in addition to Duke and the South Carolina utilities): TVA, Southern Company, LGE/KU, AECI, PowerSouth, Duke Florida, Seminole Electric Coop, JEA, and Tampa Electric.

FIGURE 11: MAPS OF THE MARKET REFORM STUDY AREAS

Source/Notes: S&P Global Market Intelligence, LLC, Mapping Tool. The JDA scenario covers the Carolinas area shown in the left most panel. The EIM and Southeast RTO scenarios cover the Southeast area shown in the right panel and the Carolinas with PJM scenario in the middle.

POTENTIAL OPERATIONAL COST SAVINGS FOR SOUTH CAROLINA

Our simulation analysis of the regional electricity markets in 2030 finds significant operational savings for South Carolina customers in each of the wholesale market reform scenarios, with the largest savings in the RTO cases, as shown in Table 11 below.

TABLE 11. 2030 OPERATIONAL COST SAVINGS OF DIFFERENT WHOLESALE MARKET REFORM OPTIONS. (IN 2022$ MILLIONS/YEAR, RELATIVE TO STATUS QUO)

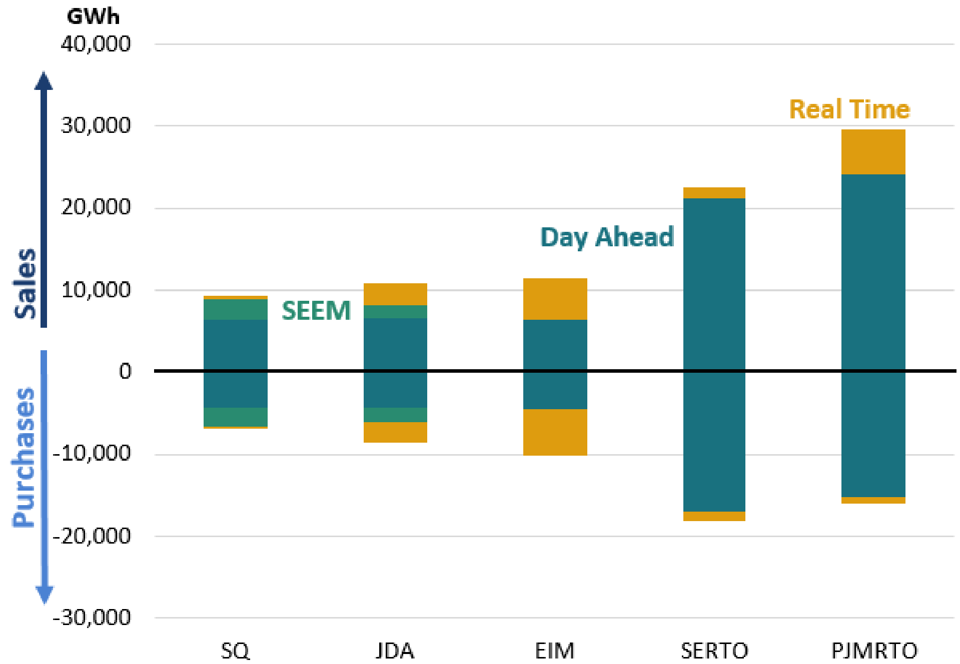
		Units		JDA		EIM		SERTO		PJM RTO
SC Balancing Authorities										
Duke	[1]	$ Mln	$	1	$	2	$	(9)	$	44
Dominion SC	[2]	$ Mln	$	7	$	6	$	64	$	74
Santee Cooper	[3]	$ Mln	$	3	$	16	$	42	$	64
South Carolina	**[4]**	**$ Mln**	**$**	**12**	**$**	**24**	**$**	**96**	**$**	**181**
Total Regional Market	[5]	$ Mln	$	15	$	99	$	228	$	322

Source/Notes:
Benefits include changes in adjusted production costs, wheeling revenues from OATT charges, and gains from trade, both within RTO footprints and external to them.
[1] to [3]: Only South Carolina share of benefits. Duke (21.34%), Dominion SC (100%), Santee Cooper (100%).
[4]: Sum of [1] to [3].
[5]: Total regional market is the sum of benefits for entire pooling region for each scenario

These operational savings reflect both the overall improvement in efficiency that these reforms provide, as well as the specific market position that South Carolina utilities hold in the new market, because not all areas of an expanded market footprint benefit equally.

Figure 12 provides some context for these operational cost savings by summarizing the bilateral and market-trades of the Carolina utilities for the status quo and the four analyzed market reform option. As the figure shows, the wholesale market reforms increase trading volumes, which (together with yielding more valuable trades) are one of the main drivers of cost reductions. The JDA and EIM both pool operations only in real time, and each increases real time trades. The RTO cases result in a more significant increase in trade volumes, largely by realizing savings available in the day-ahead energy markets.

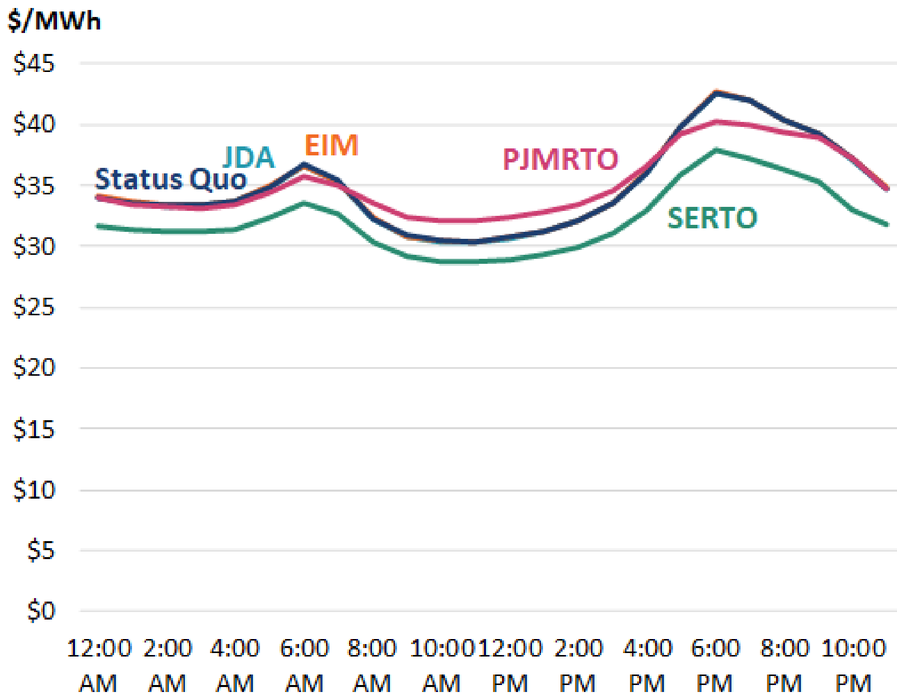
FIGURE 12: TRADING VOLUMES FOR CAROLINA UTILITIES BY WHOLESALE MARKET REFORM OPTION AND TRADING TIMEFRAME



Sources/Notes: Bars are stacked. Trading volumes show the total of Duke, Santee Cooper, and Dominion South Carolina transactions.

The average hourly prices shown in Figure 13 indicate that the average prices realized by Carolinas generators are effectively identical for the status quo, JDA, and EIM. This is because relatively little generation is settled in SEEM and real-time transactions. In contrast, the Southeast RTO market reform option uniformly lowers prices by around $3/MWh due to significant shares of solar and low-cost natural gas generation in the Southeast, which yields a regional supply curve that is shifted down and to the right relative to status quo. Conversely, the PJM option raises prices (and associated off-system sales revenues) during solar hours by around $1/MWh, lowers prices obtained by generators during the evening peak hours by around $2/MWh (as well as a slight reduction in morning hours). This is due to interactions with the solar share of the Carolina resource mix in PJM relative to the status quo. Because South Carolina is a net seller of electricity (particularly during high solar generation hours), the effect of a higher LMP for generation actually helps reduce costs to consumers in the PJM case.

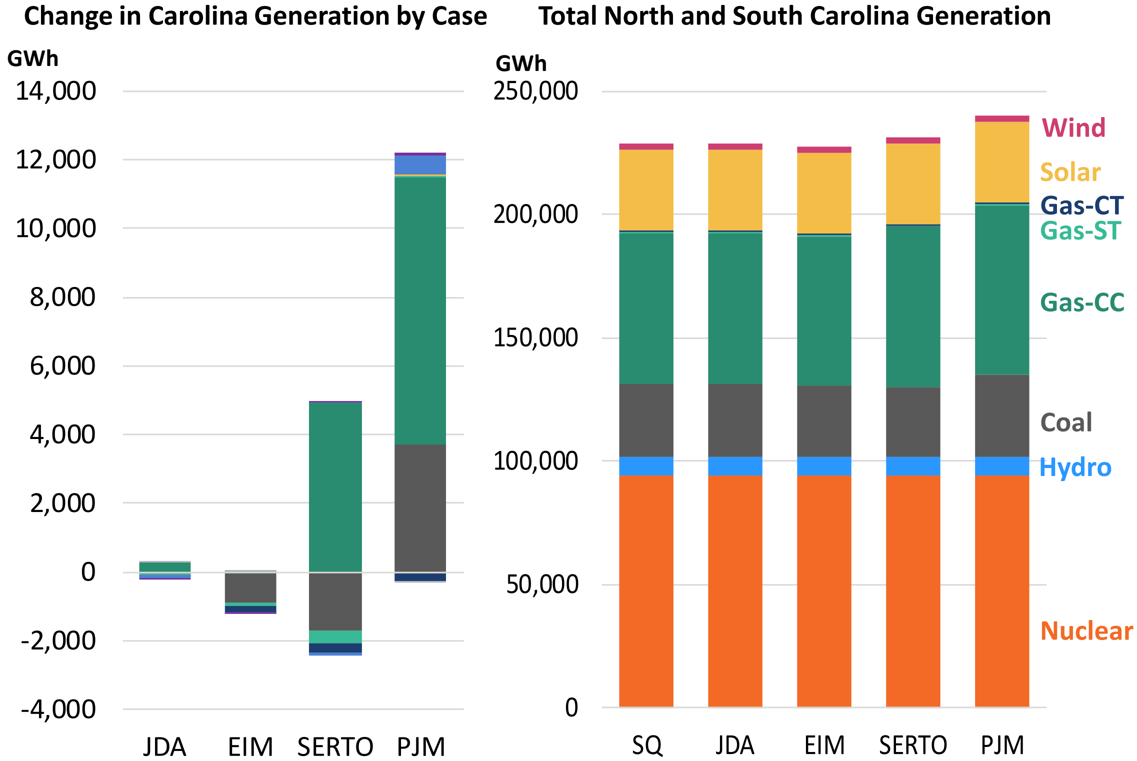
FIGURE 13: HOURLY DAY-AHEAD PRICES FOR GENERATOR OUTPUT AVERAGED ACROSS THE STUDY YEAR, BY MARKET REFORM OPTION



Notes: JDA and EIM average LMPs are nearly identical to status quo.

As shown in Figure 14, the RTO cases enable a significant increase in output from lower-cost natural gas combined-cycle generators of the three major utilities in the Carolinas. In the EIM and Southeast RTO cases, coal output in the Carolinas declines. In the PJM case, coal generation output increases.

FIGURE 14: TOTAL AND CHANGE IN CAROLINA GENERATION OUTPUT BY RESOURCE TYPE



Source/Notes: does not include generation output in the PJM portion of North Carolina.

The relative levels of the estimated operational cost savings for the different wholesale market reform options for South Carolina are supported by first principles: the JDA has a smaller footprint and lower functionality, and shows the lowest benefit; the EIM has a larger footprint (the same as the Southeast RTO case) and slightly improved functionality in how it optimizes real-time operations, which yields higher benefits; the estimated benefits for two RTO cases—with both day-ahead unit commitment and dispatch, real-time imbalance markets, and consolidated BA operations (which reduces and optimizes operating reserves)—are higher still. Appendix B presents these results and supporting study assumptions in more detail.

The finding that the RTO cases are most beneficial is robustly supported, but the finding of a contrast between the two RTO cases is subject to some observations and caveats. The overall analytical results show that joining PJM offers both higher investment cost savings and higher operational cost savings for South Carolina's utilities than being part of a Southeast RTO.

The lower projected savings for the Southeast RTO case does not reflect any difference in functionality between the two RTOs. Rather, the sources of the lower Southeast RTO savings relate to the findings that PJM offers both more peak-load diversity and more resource diversity. In contrast to PJM, the other potential members in the Southeast RTO have peak loads that are more similar to those of the Carolina utilities (which yields smaller investment cost savings) and a planned 2030 resource mix (e.g., substantial solar generation) that are also more similar to those of the Carolina utilities (which yields lower operating cost savings and off-system sales revenues).

POTENTIAL INVESTMENT COST SAVINGS FOR SOUTH CAROLINA

Joining an RTO also allows utilities to pool their demand across a greater regional footprint. Customers in different locations and states tend to draw peak demand with somewhat different time-of-day and time-of-year profiles, such that utilities within an RTO are able to share surplus generation with others when their demand is below peak demand, and draw on other utilities' surplus when their demand peaks. This diversity in load and resource mix across a larger regional system (one that ideally exceeds the size of challenging weather systems that affect both loads and resource availability) allows region-wide total capacity requirements to be reduced when compared to the case in which each utility manages its own supply and resource adequacy needs independently as in the Status Quo.

These diversity-driven benefits tend to be greatest in large regional systems that have high levels of diversity across the footprint in terms of load patterns, weather patterns, and renewable supply patterns (particularly solar), and resource types (which tend to be affected differently by weather). Moreover, the level of reserve generation capacity (the "resource adequacy requirement" or "planning reserve margin") that must be carried to meet reliability targets can be lower in a large power system because the probability of extreme conditions that simultaneously affect all portions of its footprint is lower, and the options available to address the reliability and grid resilience challenges associated with low-probability events are greater.

For South Carolina, we examined the scale of potential resource investment benefits that can be achieved by reductions in the size of capacity requirements for the different wholesale market reform options. The JDA and EIM scenarios do not offer such benefits, given that each separate utility will continue to utilize status-quo practices for meeting their individual installed capacity requirements and resource adequacy needs. Under the Southeast RTO and PJM RTO scenarios, we examine the scale of diversity benefits that can be achieved by examining 11 years of historical demand patterns (2011–2021) in the participating balancing areas within the respective market region, considering the extent to which the coincident peak (CP) load hours across the broader system declines as compared to the non-coincident peak (NCP) of each utility area considered separately. For more details see Appendix A and Appendix B.

Based on this load diversity analysis, we find that South Carolina capacity requirements could be expected to be reduced by 3.1% in the Southeast RTO case and by 6.6% in the PJM RTO case, as shown in Table 12. The PJM RTO option offers higher reductions in the installed capacity requirement due to greater peak-load diversity between the Carolina utilities and the PJM footprint (as compared to the lower peak-load diversity between Carolina and the rest of the Southeast). In both RTO cases, the Planning Reserve Margin is reduced compared to the Status Quo due to the ability to carry less capacity to meet the same reliability standards when operating across a larger footprint as mentioned above.

These installed capacity requirement reductions can be translated into investment cost savings using an approximate cost of capacity, converted to an annualized cost basis. As shown, the Southeast RTO scenario would offer approximately $120 million in annual investment-related cost savings to South Carolina's customers. If the Carolina utilities joined PJM, these investment cost savings are estimated to be approximately $200 million annually. Both of these RTO-related investment cost savings due to load diversity are likely to increase over time as the Carolina utilities add more solar generation to the footprint, which increases the value of geographically diversified regional loads and resource mix.

TABLE 12: POTENTIAL INVESTMENT COST SAVINGS FROM REDUCED CAPACITY REQUIREMENTS DUE TO LOAD DIVERSITY

Scenario achieves capacity investment savings?			No	Yes	Yes
Projected 2030 Peak Load of SC Utilities	(MW)	[1]	17,748	17,748	17,748
Load Reduction Relative to Status Quo	(%)	[2]	0%	3.1%	6.6%
2030 Regional Coincident Peak Load of SC Utilities	(MW)	[3]	n/a	17,194	16,571
Planning Reserve Margin	(%)	[4]	17.0%	14.7%	14.7%
Capacity Savings Relative to Status Quo	(MW)	[5]	0	1,043	1,759
Annualized Cost of Capacity	($/MW-Day)	[6]	n/a	$308	$308
Annualized Savings from Avoided Capacity	**($ mln/year)**	**[7]**	**$0**	**$117**	**$198**

Sources and Notes:
All dollar values expressed in 2022$.
[1]: Based on 2030 peak load forecast from South Carolina utility IRPs.
[2]: Percent reduction of SC peak load due to load diversity based on regional 4-CP and utility 4-NCP peak loads from 2011-2021 historical gross load data from FERC Form 714, as shown in Appendix A.
[3]: [1] × (1 − [2]).
[4]: For Status Quo/JDA/EIM: SC utilities' target reserve margin from IRPs.
For Southeast RTO/PJM RTO: RTO reserve margin based on PJM historical target reserve margins.
[5]: [2] × (1 + 17%) − [4] × (1 + 14.7%).
[6]: Inflation adjusted PJM 2023/2024 BRA Gross CONE.
[7]: [5] × [6] × 365.

Beyond the savings from peak-load diversity, additional investment cost savings likely will accrue from diversity of renewable generation profiles within larger geographic regions. To illustrate, consider a winter-peaking utility that invests in new solar plants. Winter peak hours occur during the early morning and late evening. If planned in isolation, the utility's solar resources provide no reliability value. The utility would therefore have to invest in alternate sources of supply to ensure resource adequacy. Consider, however, that the broader regional market peaked during daytime summer hours. If resource planning were conducted at this regional level, then the utility's solar resources would have significant resource adequacy value, and could provide that value to the utility by decreasing the capacity it would otherwise have to invest in or retain within the regional market.

The South Carolina utilities are all such winter planning systems, which means the majority of their resource adequacy risks occur during the winter without the benefit of solar generation.[113] As a result, the resource adequacy value of the 5,640 MW nameplate of solar generation in our

[113] See Duke Energy Carolinas, 2022 South Carolina Integrated Resource Plan Update, Accessed February 20, 2023; Dominion South Carolina, 2023 Integrated Resource Plan, January 30, 2023; Astrape Consulting, Reserve Margin and Effective Load Carrying Capacity (ELCC) Study, prepared for Santee Cooper, December 5, 2022.

2030 South Carolina case is very close to zero. By contrast, PJM remains a summer peaking system in which the resource adequacy value of solar is expected to remain above 20% for the next decade.[114] If the Carolinas were to join PJM, the resource adequacy risk would shift mostly to summer peak periods. However, without a more extensive evaluation using the effective load carrying capability (ELCC) method, it is difficult to know precisely the value of Carolina solar in a PJM participation context. Moreover, the ELCC value of solar in PJM is a function of both aggregate load shapes and the level of solar deployment, which means there is inherent uncertainty about the future resource adequacy value of solar resources. However, conservatively assuming a 10% ELCC value for Carolina solar resources in 2030 in the PJM participation context, the 5,640 MW of projected solar generation in our study would be worth 564 MW in resource adequacy terms, which (at the capacity values assumed in Table 25) would yield an additional annual investment cost savings of $63 million for South Carolina customers.

The Southeast RTO option may offer a similar value, but without the system-wide ELCC analysis that PJM has already performed for its system, it is difficult to know. However, because the Southeast is expected to develop a significant amount of solar resources and tends to have a heating and cooling demand profile more similar to that in South Carolina, the resource adequacy value of Carolina solar resources within a Southeast RTO will likely be lower than their value in PJM.[115]

We recommend that, prior to finalizing a decision to pursue an RTO, South Carolina policymakers conduct an ELCC study to assess the reliability value of solar in the broader RTO context relative to South Carolina alone.

Investment savings due to load diversity alone, however, explains only a portion of potential benefits and does not capture the cost savings from having access to a market with pooled capacity resources. These additional market benefits are discussed in Section III.E and Appendix B.

SUMMARY OF COST/BENEFIT ANALYSIS OF WHOLESALE MARKET REFORMS FOR SOUTH CAROLINA CONSUMERS

Combining benefits from operational savings, benefits from investment cost savings, and estimated costs to administer wholesale market reforms, we estimate that some of the wholesale market reforms offer significant benefits for South Carolina consumers through

[114] PJM, December 2022 Effective Load Carrying Capability (ELCC) Report, January 6, 2023.

[115] Georgia Power, Georgia Power's 2022 Integrated Resource Plan, Docket 44160, November 17, 2021.

market reform savings that significantly exceed their costs. As shown in Table 13, full RTO-based market reforms (or alternatives that include both day-ahead and real-time energy markets as well as a regional resource adequacy framework) offer significantly higher net benefits, ranging from $140 million to $360 million annually. On the other hand, both JDA and EIM options may offer benefits that only modestly exceed JDA and EIM administrative cost—although the simulations do not capture certain real-time market challenges (such as intra-hour balancing), which would mean the simulations understate these real-time market benefits.

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[116]	$9	**$1–$4**
Southeast EIM	$22–$27	N/A[116]	$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].

[116] Capacity investment benefits similar to those from RTO participation could be enabled through the creation of a region-wide resource adequacy framework, such as the new Western Resource Adequacy Program (WRAP), as noted earlier.

H. Recommendations for Wholesale Market Reforms

Based on these findings regarding wholesale market reforms, we recommend that South Carolina consider immediately initiating processes to:

- Join an existing RTO (i.e., PJM), coordinating with North Carolina policymakers (South Carolina would retain authority over the current vertically integrated utility model and resource planning framework, including any potential reforms); or
- Provided that neighboring states and utilities show interest, initiate multi-state efforts to create a new Southeast RTO market; or
- Pursue both an EIM and joint regional resource adequacy program without entering an RTO framework. This option could be achieved by joining with PJM in a non-RTO partnership (ideally together with North Carolina), or with other interested neighboring states and their utilities; and
- Authorize the PSC to review and approve each utility's regional integration plan subject to defined criteria and timelines. [117]

[117] As two examples of legislation in other states, Colorado Senate Bill 21-072 and Nevada Senate Bill 448 establish relevant authorities, timelines, and evaluation criteria for regional market integration. Both states offer relevant experience for South Carolina given their similar, vertically integrated utility models and reliance on integrated resource planning under state regulatory oversight. Source: General Assembly of the State of Colorado, Colorado Senate Bill 21-072, 2021 Regular Session, signed June 24, 2021; Nevada Legislature, Nevada Senate Bill 448, 81st Session, (2021), signed June 10, 2021.

III. Resource Planning and Competitive Investment Reforms

A. Overview of Potential Resource Investment Reforms

Currently in South Carolina, vertically integrated utilities are responsible to serve the supply needs of customers within their respective service territories, and hence are the entity conducting integrated planning to identify, build, own, or (in some cases) contract for energy supply resources, subject to PSC oversight and approval. The utilities' prudently incurred investment costs are then incorporated into the rate base and are recovered in customers' retail bills along with a return on investment.

Resource planning and completive supply investment reforms, as illustrated in Figure 15, would seek to achieve greater statewide coordination or a more competitive approach to selecting and building resources. A competitive approach could allow customers to benefit by allowing them to select the lowest-cost provider of new generation, batteries, demand response, or other supply resources, including from IPPs if they can offer wholesale power at a lower price than the utility. Competitive reforms would leverage competition to drive down capital costs, increase the value of existing capacity, expand low-cost demand response and energy efficiency options, guide cost-effective resource retirement decisions, and ultimately reduce customer costs. The reforms we examine range from incremental to foundational, and consider:

- **Introducing a statewide IRP across all South Carolina utilities**, under which utilities, the PSC, or other state agencies would conduct resource planning on a joint basis with the goal of informing policy, pooling resource adequacy needs for cost savings, or making improved investment choices on a statewide basis;
- **Expanding the role of competitive solicitations within utility IRPs,** so that IPPs, distributed resource aggregators, and other third-party resource developers would have increasing opportunities to propose resources within competitive resource solicitation processes. A state agency or independent evaluator would select the winning resources, with third-party developers being awarded a contract to develop a portion of needed supply resources if they can do so at a lower cost than the incumbent utility. South Carolina is already in the early stages of gaining experience with competitive solicitations based on provisions in the 2019

Energy Freedom Act, experience that can inform ongoing enhancements to improve effectiveness and transparency. Participation in an RTO can further improve the effectiveness of such a program;

- **Transitioning to partial or full reliance on competitive supply investments**, a model under which resource supply investments are attracted by competitive market prices, thus shifting future investment decisions and investment risks to resource owners (shifting away from integrated planning and regulated cost recovery). Full reliance on competitive supply investments can become a meaningful option for South Carolina in the event that the state begins participation in an RTO with a sufficiently robust investment model; and
- **Securitization of costs associated with retiring thermal assets**, which offers one option for managing the financial arrangements associated with utility-owned thermal assets that are no longer cost-effective to continue operating but whose undepreciated investment costs have not yet been recovered from customers through rates.

South Carolina can implement these reforms under state authorities without any cooperation or coordination with other states. However, for the state to have a meaningful path for full transition to competitive supply investments, it would first need to begin participation in a regional RTO through which the transparent signal of resource needs and associated prices can be expressed.

FIGURE 15: POTENTIAL ROLE OF COMPETITIVE SUPPLY INVESTMENT REFORMS IN SOUTH CAROLINA

	Generation	Transmission	Distribution	Retail Customers
Status Quo: Vertically Integrated Utility	**Resource Operations** • Utility: Manages generation & transmission scheduling **Supply Investments** • Utility: Conducts integrated planning. Builds and owns resources	**Interregional Energy Trade** • Utilities: Manages generation & transmission scheduling • SEEM: Utilities run & participate in SEEM, to support enhanced bilateral trade **Transmission System** • Utility: Plans & builds bulk transmission	**Distribution System** • Utility: Plans & builds distribution system	**Customer Deliveries** • Utility: Sources all electricity supply and bills customers for associated cost
Resource Planning & Competitive Investments	**Supply Investments** • IPPs: Can develop new resources (competing on price)			

Notes: This figure illustrates which roles in each section of the electricity value chain are changed by each area of reform. Blank areas indicate where there are no or minimal changes to the existing industry structure under a given reform area.

B. Status Quo with Utility Integrated Resource Planning

DESCRIPTION OF STATUS QUO IN SOUTH CAROLINA

Generation investment decisions in South Carolina today are primarily undertaken by the vertically integrated utilities, as mediated through the Integrated Resource Planning (IRP) process. An IRP combines investments in generation, energy efficiency, and demand side management to meet changes in load over a 15-year forecast (accounting for generation retirements). An IRP compares a set of resource portfolios that each meet customer needs. These portfolios are compared using economic and financial analysis, reliability and risk evaluations, environmental assessment, and other considerations related to the public interest. Public comment is required for IRPs to ensure they consider stakeholder perspectives and are potentially refined in light of feedback.

South Carolina requires its electric utilities to prepare integrated resource plans at least every three years (with annual updates).[118] Following 2019's Act 62, IRPs from the investor-owned utilities are reviewed for approval by the Public Service Commission after an open comment process.[119] South Carolina law provides that "*The commission shall approve an electrical utility's [IRP]… if the Commission determines that the proposed integrated resource plan represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed.*" Through these IRP processes, utilities propose and the PSC approves plans to build or procure new generation resources, and retire older generation resources. The utilities subsequently receive approval to build generation through the CPCN process. Utilities can then allocate prudently incurred investment costs required to develop the selected resources to ratepayers, including recovering an approved rate of return on the capital invested.

Historically, the South Carolina IRPs have focused on self-build generation rather than considering contracts with IPPs or competitive solicitations, and have featured limited coordination among South Carolina utilities.[120] Going forward, based on reforms in the 2019 Energy Freedom Act, competitive solicitations may play a greater role (see Section III.D below).

ADVANTAGES OF STATUS QUO APPROACH

IRP is a central planning process for generation investment; in comparison to a decentralized model with many competing actors, IRP allows for coordination of all infrastructure investment across every generator in the fleet and every transmission facility in a utility's footprint. New generators can be built on the site of recently retired generators (saving on interconnection and other costs and reducing job displacement from retirement), and the transmission interactions

[118] Specifically, the South Carolina Public Service Commission currently requires preparation of IRPs every three years that plan system reliability on a 15-year horizon. The IRP process as laid out in SC Act 62 includes: (1) forecasting future electric demand; (2) identifying goals and requirements of the process; (3) developing a set of resource portfolios to meet the demand and goals; (4) evaluating those portfolios across cost, fairness, and environmental dimensions; and (5) choosing a preferred plan. S.C. Code § 58-37-40; see also U.S. Environmental Protection Agency, "State Energy and Environment Guide to Action: Electricity Resource Planning and Procurement," 2022.

[119] The IRP of Santee Cooper must include additional specific elements: (a) an analysis of long-term power supply alternatives, with PSC evaluation of self-build generation and transmission options compared with various alternatives, including power purchase agreements, market purchases from an RTO, and joining an RTO; (b) a PSC analysis of any potential cost savings that might accrue to ratepayers from the retirement of remaining coal generation assets; and (c) evaluation of a resource portfolio that meets a net zero carbon emission goal by the year 2050.

[120] Duke prepares a combined IRP among its South Carolina and North Carolina utilities.

of one generator addition or retirement can be played off the deployment of another generator. These interactive effects can, if effectively deployed, lead to cost savings.

While the IRP process in South Carolina is focused primarily on electric reliability and financial concerns (costs and benefits, but also financial risks), it takes into account non-financial considerations, such as environmental impacts, as well. The IRP process can be used to help accomplish the state's broader social goals related to jobs, affordability, and the distribution of impacts on different communities.

DISADVANTAGES OF STATUS QUO APPROACH

Today's utility IRPs feature little regional coordination among utilities: each resource adequacy analysis (demonstrating that sufficient generation is planned for to meet reliability targets) is limited to the resources of that company (and in the case of Duke, across multiple states). This necessarily results in a higher quantity of needed generation, both because the installed reserve margin must be higher for the utility to handle operational risks on its own, and because regional diversity benefits are not enjoyed.

If focusing on self-build, historical IRPs have offered a more limited set of options for consideration compared to what could be considered in a fully competitive model with many potential resource providers identifying and proposing a wider array of projects. For example, a competitive solicitation-based approach could consider utility projects alongside IPP projects, third-party demand response aggregations, imports from outside the state, and a range of short- or long-term supply options. The utility self-build option may be the most cost-effective option in some cases, but not others. In at least some cases, an IPP building under a long-term Power Purchase Agreement (PPA) contract could have access to a lower-cost site, a more cost effective technology type such as cogeneration or demand response, or have more competitive construction terms. Different developers have different outlooks on the energy market and differing hedging strategies, which can impact their perceived risk or risk exposure, and potentially reduce their cost of capital. Such options are not possible to consider if the IRP processes do not regularly consider third-party supply options.

The current IRP approach does not have a mechanism through which the utilities in South Carolina and neighboring states can coordinate the timing and volume of capacity investments. A statewide IRP could be used to achieve some level of alignment or coordination. A regional capacity market would go further to create a relatively standardized and liquid exchange through which utilities could manage small surpluses and deficits, for example potentially deferring new plant builds because of a temporary availability of low-cost capacity from a neighboring utility.

Whether opportunities for capacity sharing were identified through a statewide IRP processes or via a fungible capacity market, customers from both utilities would benefit from such an exchange (the selling utility because capacity sales can offset the cost of their supply and the buying utility because the short-term purchase is less expensive than expediting new investment).

Under the current IRP model, customers face the risk of errors or lack of foresight in investment choices. For example, a resource investment that appeared prudent at one time can prove to be costly in retrospect if changes to fuel prices, environmental regulations, or other market conditions undermine the originally expected value proposition and the resource must retire early or stand idle much of the time. Customers would be required to pay for the cost recovery on such an asset as long as the costs were approved and prudently incurred, even if customers are not receiving the originally expected benefits. Finally, under cost of service regulation, utilities are able recover a regulated rate of return on the entire rate base, which provides a financial incentive to make larger capital investments that can be at odds with customers' interest to reduce investment costs while maintaining quality of service and resource adequacy.

C. Statewide Resource Planning Across All Utilities in South Carolina

DESCRIPTION AND RELEVANT CASE STUDIES

In South Carolina, each utility conducts a separate IRP process with no requirement for coordination across the utilities on the selected supply plans. Some other jurisdictions utilize a statewide IRP or similar process conducted or overseen by a government entity in order to achieve state policy goals along with the aims of the IRP in a coordinated manner. Depending on the underlying purpose of the mechanism in each jurisdiction, the process may include modeling to inform specific policy questions; IRP-like assessments to determine the scale of resource needs and preferred resource types on a region-wide basis; and/or competitive solicitations to procure some or all of the needed supply. California, New York, and Ontario all utilize distinct variations of an IRP or IRP-like processes that cross all utility areas within the relevant jurisdiction and that are suited to achieving their specific policy aims.[121] Their approaches involve:

[121] See general discussion of these processes in: California Public Utilities Commission, "Utility Scale Request for Offer (RFO),"2021; K. Spees, et al., Qualitative Analysis of Resource Adequacy Structures for New York, May 19, 2020; IESO, Planning and Forecasting Overview, accessed January 12, 2023.

- **California**: The California Public Utilities Commission (CPUC), in coordination with the California Energy Commission (CEC) and CAISO, oversees IRP processes. The IRP process has evolved extensively in the decades since statewide restructuring to meet a variety of policy goals, including to: achieve competition in the electricity sector; ensure resource adequacy needs and manage customers' financial exposure in the restructured environment; and meet state environmental policy goals, including updates in 2018 to meet the provisions of SB 350, the Clean Energy and Pollution Reduction Act.[122] SB 350 outlines emissions reductions targets and requires large utilities to submit IRPs that plan for resource needs and ensure greenhouse gas reductions and clean energy integration.[123] The CPUC, in coordination with CEC and CAISO, and considering commenter input, conducts modeling to identify a Reference System Plan of resources to meet forecasted demand, greenhouse gas, reliability, and RPS requirements. In the second phase of planning, each utility develops individual IRPs consistent with the Reference Plan. The CPUC aggregates these individual plans, assesses system reliability, and recommends a comprehensive Preferred System Plan.[124] In the first two-year iteration of the current process, the Commission approved a plan that calls for utility procurements for 12 GW of new, clean resources by 2030, and no new natural gas plants.[125] Once the procurement plans are approved, each utility conducts competitive solicitations under the oversight of the CPUC and an independent evaluator, contract with the winning resource developers, and pass the costs along to retail customers. This approach incorporates a substantial role for state agencies to define the needed resource mix in the context of state policy goals and with a focus on meeting statewide environmental mandates.
- **New York:** New York's power sector is structured to rely on competitive resource investments that for the most part have been attracted via the NYISO wholesale capacity and energy markets. More recently and going forward, resource investment needs in New York are primarily driven by the State's 100% by 2040 clean electricity requirements, with sub-goals for specific resource types including storage, offshore wind, and other renewables. To meet both reliability and environmental policy goals, New York relies on several state agencies and committees to conduct statewide resource planning and modeling, with primary roles for the

[122] See California Public Utility Commission, Integrated Resource Plan and Long Term Procurement Plan (IRP-LTPP).

[123] California Senate Bill 350, De León, Clean Energy and Pollution Reduction Act of 2015, approved by Governor October 7, 2015.

[124] California Public Utilities Commission (CPUC), Order Instituting Rulemaking Implement Senate Bill 520 And Address Other Matters Related To Provider Of Last Resort, Rulemaking 21-03-011, March 25, 2021.

[125] M. Specht, "The Basics of Integrated Resource Planning in California," Union of Concerned Scientists, May 23, 2019.

New York State Energy Research and Development Authority (NYSERDA) to conduct or support modeling efforts, and the Department of Public Service (DPS) to approve programs and solicitations to meet identified needs and state legislative requirements, evaluating various alternatives in light of legislatively-defined criteria including cost, reliability, equity, and environmental goals.[126] In the case of large-scale incremental resource needs, the DPS approves the details of method of procurement and contract structure and directs NYSERDA to conduct competitive solicitations for the needed resources; NYSERDA selects the winning bidders (subject to DPS approval) and acts as the contractual counterparty; and the costs of supply under contract are then passed to customers of all utilities across the state.

- **Ontario**: Ontario's Independent Electricity System Operator (IESO) is a government agency that takes responsibility for both operating the wholesale electricity markets and for planning and procuring energy in a single-buyer model, relieving utilities completely of planning and procurement responsibility. The IESO models reliability, demand, and resource adequacy annually, and translates the planning needs into procurement requirements, while considering national and provincial policy mandates, costs, and risks. Depending on the timeline of any identified needs, the IESO employs a capacity auction for near-term peak demands; medium- and long-term competitive contract solicitations; and technology-specific Requests for Proposals (RFPs) to secure needed electricity supply. Under this "single buyer" procurement model, all supply resources are developed under contract with the IESO and associated procurement costs are allocated to customers of all utilities as a surcharge on customer bills (no individual contract is tied to a specific utility or its distribution system customers).

POTENTIAL ADVANTAGES

Potential advantages of a statewide IRP process could include:

- If conducted primarily as modeling or informational exercises, statewide assessments can inform policymakers, individual utilities, and the public about the possible implications of a potential policy decision or statewide resource strategy, for example in the context of assessing major environmental policies the consumer cost impacts of which may not yet be known.

[126] See New York Department of Public Service, Order on Implementation of the Climate Leadership and Community Protection Act, May 12, 2022.

- Coordination of planning activities across a larger planning footprint achieves a reduction in the aggregate requirement for resources due to load diversity and a potential small reduction in the installed reserve margin necessary to preserve target reliability.
- Coordinated planning could achieve a more efficient resource selection, timing of entry and retirement, siting, or self-consistent resource mix.
- Potential economies of scale in constructing larger and more efficient assets to serve statewide demand, a benefit that could arise primarily if individual utilities' assessments would tend to procure multiple smaller plants (individually lower cost but collectively a higher cost).
- If statewide IRP is followed by competitive solicitations to meet the defined needs, the benefits could include greater competition and potentially lower cost resource procurements (see more discussion in the following section on competitive IRP reforms).
- If statewide IRP is conducted in the context of full state restructuring (i.e., transition to primary reliance on a competitive investment model and retail choice as discussed further in Section III.E and Section IV respectively), 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 (e.g., consideration of environmental policy, managing price volatility, employment impact assessments, and equity).

POTENTIAL DISADVANTAGES

Potential disadvantages of statewide IRP processes could include:

- The risk of uneconomic investments remains on the ratepayer for any approved investments.
- Mechanism to hold state planning agencies accountable for decisions is not as clear or well established as oversight of traditional utility cost recovery.
- State agencies may have less information and visibility into each utility's resources, customers, and operations than the utilities themselves.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

The role and benefits that could be associated with a statewide IRP would depend on whether and to what extent the state wishes to pursue other market reforms discussed in this paper to the resource planning and investment model and/or to introduce partial or full retail choice. We therefore suggest that:

- If South Carolina policymakers decide to rely mainly on the historical status quo approach of utility planning, investment, and retail provision, the role and relevance of statewide resource planning would be primarily to provide information and (depending on the design) yield some savings associated with pooling of resource adequacy across a relatively modest footprint. A principal value of statewide IRP would be for the PSC, ORS, and legislature to use regularized or ad hoc studies to offer independent assessments to inform specific policy choices, and/or enhance the PSC's ability to review and scrutinize the separate utilities' IRPs during approval processes.
- If South Carolina opts to incrementally expand the role of third-party resource suppliers and competitive solicitations to meet future needs (as discussed in the following Section III.D), then a statewide IRP process could take on a more substantial role in determining the contours of such a solicitation, including evaluating the desired statewide resource mix and defining the volume or type of supply to be procured by a state agency or the separate utilities.
- Finally, if South Carolina eventually pursues a restructured competitive supply investment model (as discussed in Section III.D below), then a periodic statewide IRP process could be used to identify and assess the need for contracts and resource investments to serve policy goals that will not otherwise be addressed by a purely market-based investment model.

To supplement or replace individual utility IRP processes with a statewide process, the legislature may need to authorize or direct state agencies (likely the PSC) to take on the defined resource planning roles. The legislature would also need to allocate responsibility to the PSC, ORS, separate utilities, or another entity for each element of the planning process: who models resource need, who solicits supply offers to meet statewide need, who approves the statewide solicitations, how an independent evaluator is relied upon, and who is the counterparty for the bids chosen.

We further note that the role of statewide planning may differ for customers of investor-owned utilities, versus customers of public power entities. For IOU customers, the outcomes of any future statewide planning process could be to direct the utilities to self-supply, solicit contracts, sign contracts selected by a state agency, or pass the costs of a state-agency-signed contracts to their customers. For public power customers, the outcomes of any statewide planning process could instead result in informational findings and the option (but not the requirement) to participate in any recommended self-supply or contract solicitation activities.

D. Expanding the Role of Competitive Solicitations in Utility IRPs

DESCRIPTION AND RELEVANT CASE STUDIES

With adoption of the 2019 Energy Freedom Act, South Carolina has authorized (but not required) the use of competitive solicitations for new renewable developments and for assessing the cost-effectiveness of major new generating facilities.[127] Under this new framework, the PSC has new authorities to require the use of competitive solicitations if deemed in the public interest, including the ability of the PSC to hire an unbiased independent evaluator and ensure that a competitive solicitation is conducted under PSC-approved processes. South Carolina is in the early stages of developing and implementing such processes, which are the subject of several ongoing dockets, as well as a soon-to-be-completed all-source competitive procurement in the Dominion utility area.[128] The outcomes of these dockets and early solicitations can help to inform and improve procurement and oversight processes; as can the consideration of best practices and lessons learned from other states' competitive solicitation processes.

In developing and refining solicitation processes, typical considerations include:[129]

- **Determination of the resource need and timing,** such as meeting either reliability requirements (i.e., winter or summer capacity need) while considering policy goals (e.g., by having renewable or battery storage requirements) or other system needs identified in an IRP process.
- **Timeframe and duration of procurements,** including consideration of whether short-term commitments can be considered alongside new resources that could be developed under long-term contracts.

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[127] Specifically, "*The commission is authorized to open a generic docket for the purposes of creating programs for the competitive procurement of energy and capacity from renewable energy facilities by an electrical utility within the utility's balancing authority area if the commission determines such action to be in the public interest.*" South Carolina Office of Regulatory Staff, Summary of the South Carolina Energy Freedom Act, September 2019.

[128] Public Service Commission of South Carolina, Docket No. 2021-93-E, Order No. 2022-27, January 11, 2022.

[129] See additional discussion of competitive solicitation experience and best practice, see: Dr. Fredrich Kahrl, 3rdRail Inc., All-Source Competitive Solicitations: State and Electric Utility Practices, March 2021.; J. Wilson et al., Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement, April 2020.; J. Wilson, Implementing All-Source Procurement in the Carolinas, February 26, 2021.; K. Spees, et al., The Brattle Group, Enhancing the Efficiency of Resource Adequacy Planning and Procurements in the Midcontinent ISO Footprint, November 2015.

- **Whether to use technology-specific procurements or consider all-source procurements.** Technology-specific procurements make it easier to compare different technologies on a like-to-like basis but all-resource procurements can typically produce better overall results by allowing consideration of more options, broadening competition, and allowing consideration of complementary resources.
- **Whether and how to stipulate standard contract terms and volumes**. Standardized contract forms enable the solicitation to more readily compare offer prices across different bidders, but may implicitly restrict competition of the specified contracts or product ratios (e.g., ratio of energy to capacity) in a way that is tied too closely to an assumed resource type. To more readily compare many alternative technologies, one option is to define a total procurement need across clearly defined products and allow bidders to self-select their proposed product mix.
- **Assessment processes and criteria.** These typically focus on total net resource cost to meet the defined adequacy need, and can utilize a modeling assessment to project total net cost of service depending on the portfolio of resources that would be selected from the procurement.
- **Role of an independent evaluator and other controls to ensure unbiased resource selection.** Best practice for supporting fair evaluation includes transparent rules and processes and an independent evaluator hired by a state agency that selects the winning resources. Particularly in solicitations where utilities are allowed to propose self-supply processes, the role of a state agency with independent evaluator support becomes critical to avoid the opportunity or perception that utility-proposed projects may be unfairly advantaged.

Some states and utilities are utilizing all-source competitive procurements as a tool to discover market prices, select a lower-cost resource portfolio, and attract innovative projects. Notable examples where this strategy has been implemented include:

- **Xcel Colorado:** Xcel administers a two-phase process that the Colorado Public Utilities Commission (COPUC) reviews. In Phase 1, the utility determines needs, resources, carbon costs, and provides scenarios to meet those needs instead of a portfolio of resources. Phase 2 includes an all-source RFP with bidding for intermittent, dispatchable resources and an independent evaluator. The utility may bid up to 50% of the defined need with self-supply projects. Selected bids are then included in system planning model analysis. A 2017 all-source procurement attracted 417 bids, with bid prices including $0.017/kWh for wind, $0.023/kWh for solar, and $0.03/kWh for solar-plus-storage (much lower than prevailing $0.126/kWh residential prices at the time).[130] The selected portfolio was estimated to save customers over $200 million compared to the utility's original preferred portfolio.[131]

- **Northern Indiana Public Service Company (NIPSCO):** NIPSCO conducted all-source RFPs to inform their IRP, attracting 90 bids in 2018 and 182 bids in 2021. Average bid prices from NIPSCO's 2018 All-Source Competitive Solicitation (ASCS) were on the lower end or below the low end of the range of prices from the prior 2016 IRP process, which did not utilize ASCS.[132] The result of the all-source procurement identified resources offering supply at prices at less than half of the cost to operate the utility's existing coal fleet.[133]
- **El Paso Electric (EPE):** EPE issues yearly All Source RFPs to obtain short term and/or long-term cost effective resources to meet capacity needs identified through initial resource planning studies. EPE evaluates proposals in two stages, first on levelized cost of electricity by type of resource and type of proposal, shortlists bids, and then asks for Best and Final offers to determine optimal winning bids. The process is then evaluated by an independent evaluator.[134]

POTENTIAL ADVANTAGES

The potential advantages of incrementally expanding the role of competitive solicitations into utility or statewide IRPs include:

- Increased competitive pressures and opportunity to identify lower-cost providers and sites.
- All-source solicitations create opportunity to further reduce costs by identifying an overall lower-cost resource mix (in addition to applying the competitive pressures on individual resource costs). All-source solicitations can attract innovation from new technologies that might not otherwise have been considered in the IRP, and allow complementary technologies (such as batteries and solar) to offer their separate or combined value in distinct offer structures.

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[130] Procurement, Xcel Energy Achieves Record-Low Procurement Costs, June 5, 2021.

[131] Rocky Mountain Institute, How to Build Clean Energy Portfolios: A Practical Guide to Next-Generation Procurement Processes, 2020.

[132] Dr. Fredrich Kahrl, 3rdRail Inc., All-Source Competitive Solicitations: State and Electric Utility Practices, March 2021.

[133] Utility Dive, NIPSCO to replace coal with 2.3 GW of solar, storage in latest RFP, October 9, 2019.

[134] El Paso Electric, 2021 All Source Request for Proposal for Electric Power Supply and Load Management Resources for Texas, December 3, 2021.

- Provides a “market test” and a visible competitive price against which regulators and the public can validate timing and cost of IRP-identified investment decisions, retirement decisions, and resource mix.
- Can increase transparency and stakeholder involvement. Publication of solicitation offer prices, volumes, and other statistics can inform other utilities, public power, and end-use consumers in the state about the availability, technologies, and potential price points that could inform their own separate bilateral agreements.
- If considering short-term contracts with existing resources or imports (alongside consideration of long-term contracts for new resources), this can sometimes identify low-cost options available for a temporary period, thus deferring the need to pay the full cost of new resources for a time.
- Regularized state processes following best practice and independent evaluations can spur and retain investor interest, such that they will be incentivized to develop a robust pipeline of projects for potential consideration.

POTENTIAL DISADVANTAGES

The potential disadvantages of expanding the role of competitive solicitations into utility or statewide IRPs include:

- Can introduce complexity into IRP processes, procurement processes require thoughtful design, oversight, and implementation to be successful.
- Complexity and protections required to ensure fair evaluation of utility self-supply versus third-party proposed projects; for example by assigning responsibility for managing the process and resource selection to a state agency or independent evaluator.
- Utilities have an incentive to pursue self-supply rather than engage in long-term contracts, given that: (a) self-supply creates opportunity to expand the rate base and associated shareholder returns; and (b) long-term contracts have the effect of imposing “imputed debt” costs on the utility, similar to impact of taking on debt.[135]
- Soliciting offers for a well-defined, standardized product or a single resource type simplifies selection to a simple evaluation of price, but removes the benefits of being able to assess a wider array of technologies with different value attributes.

[135] See discussion of imputed debt methodology: Rhode Island Public Utility Commission, Information request AG-2-1, accessed February 15, 2023.

- Evaluating bids and assessing new technologies with highly divergent value propositions can be time consuming and may sometimes be less amenable to standardized assessment processes; new evaluation metrics are needed to compare renewables and storage with traditional resources or determine what portfolios of technologies to consider in a grouped fashion.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

South Carolina may benefit from expanding the role of competitive, all-source solicitations to meet defined needs within individual utility or any future statewide IRP processes. South Carolina is presently and will in the near future gain more experience with competitive renewable and all-source solicitations, experience that (along with experience in other states) can inform the most advantageous oversight and procurement model. Further expanding the role of competitive solicitations can be achieved by options such as:

- Requiring (rather than the current "allowing") future supply needs identified in IRP to be met through all-source competitive solicitations.
- Determination of whether utility self-supply projects would be allowed to compete alongside third-party suppliers and, if so, what mechanisms would be implemented to ensure that all bids are considered on an equal basis. For example, by placing primary responsibility for conducting solicitations with a state agency and with support from an independent evaluator.
- Determining whether state agencies or utilities will be the entity required to sign contracts with winning bidders. In the latter case, determining how to compensate utilities for the cost of contract management and effects of "imputed debt."
- Determination of whether and how electric cooperatives, municipally owned utilities, and other public power entities can participate in resource selection and receive a share of the selected supply, potentially on an opt-in basis.
- Establishing and refining regularized processes consistent with best practice, including transparent timelines, assessment criteria, and sufficient flexibility to consider a wide array of potential proposed projects.

E. Transition to Partial or Full Reliance on Competitive Supply Investments

DESCRIPTION AND RELEVANT CASE STUDIES

In the 1990s and early 2000s, many U.S. states and international jurisdictions restructured to transition from the vertically integrated utility model, with the goals of using competition to drive down costs and support sector innovation.[136] Full transition to a competitive investment model involves shifting all decision-making around future resource investments away from the utility IRP model, and instead relying on competitive "merchant" resource developers to build needed supply resources. Under the competitive investment model, private companies are incentivized to build new generation, demand response, or storage resources on the basis of a competitive market price, or else based on bilateral contracts voluntarily struck with customers or competitive retail providers.

PJM's capacity market results illustrate the advantages and disadvantages of transitioning to a competitive investment model, in particular the advantages of relying on competitive forces to attract a diverse set of resources and keep costs low.[137] While the PJM capacity market serves an important role in pooling resource adequacy in both vertically integrated and restructured regulatory frameworks, it plays a unique and critical role in influencing resource investment in the restructured context. Over the last decade of the PJM capacity market, prices have remained quite low (approximately 27% of the estimated cost of building of new generation) but the market has attracted approximately 176 GW of incremental low-cost supply from non-traditional resources including demand response, uprates to existing generators, net imports, and energy efficiency.[138] More recently as additional coal plant retirements have created the need for new supply, the capacity market has attracted approximately 35 GW of new generation, primarily gas combined-cycle plants (even though market prices have never risen to more than 60% of the

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[136] See, for example, a detailed history of restructuring across the six New England states. Reishus Consulting, Electric Restructuring in New England—A Look Back, prepared for the New England States Committee on Electricity (NESCOE), December 2015.

[137] Several other options for attracting market-based investments for resource adequacy exist around the globe, but the capacity market model is the primary option utilized in the U.S. RTO/ISO markets. For a discussion of alternative structures, see J. Pfeifenberger, et al., A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs, September 2009.

[138] PJM, 2022/2023 RPM Base Residual Auction Results, accessed February 20, 2023.

estimated cost of new entry, CONE).[139] PJM's capacity market successfully achieves twin design objectives: accounting for pooled resource adequacy needs, and attracting new supply in a low cost environment. It accomplishes this without interfering in the IRPs of vertically integrated utilities. The PJM capacity market's success at attracting new entry on a competitive basis stands in contrast to other capacity market designs (such as MISO's) that lack certain design features to achieve these objectives. Therefore, South Carolina policymakers interested in a fully competitive resource investment model should seek an RTO capacity market that is designed to be flexible to facilitate different participation models (vertically integrated or restructured) while achieving these important design objectives.

The primary criticisms of the PJM capacity market have focused on the pace of changes to market rules as they are updated to reflect emerging reliability needs; administrative judgement and estimation errors with respect to procurement parameters (particularly with respect to peak load over-forecasting); and the lack of mechanisms within the market to reflect states' environmental policy goals.[140]

States representing approximately 57% of all U.S. energy demand rely on competitive supply investments to meet at least a portion of their resource adequacy needs.[141] These are the same states that have introduced some level of competition into the retail market, given the structural linkage between competitive supply investments and retail choice (i.e., for customers to exercise a meaningful level of choice in their power supply, they must be able to choose from among many potential sellers of power). At the conclusion of a full restructuring transition, segments of the electricity supply chain considered to be natural monopolies (transmission and distribution) are continued to be regulated by the state while the competitive portions of the electricity supply

[139] Note this is referencing the base PJM RTO clearing price, while locational capacity prices have risen beyond this level due to increased need in capacity constrained areas of PJM. See PJM, 2022/2023 RPM Base Residual Auction Results, accessed February 20, 2023.

[140] These concerns are among the reasons that most states and large utilities relying on vertically integrated IRP models in the PJM region have chosen to opt out of capacity market participation under the Fixed Resource Requirement Alternative (FRR), even while they fully participate in the RTO energy market and transmission planning processes. Other RTOs such as MISO and SPP also offer many of the same advantages of the PJM RTO in terms of energy market coordination and regional transmission planning, but do not (yet) offer capacity market that has proven to attract supply investments when needed. See PJM, Securing Resources Through the Fixed Resource Requirement, September 23, 2022.

[141] Energy Information Agency (EIA), Annual Electric Power Industry Report, Form EIA-861, detailed data files, accessed February 8, 2023.

chain (generation investment, generation operations, and retail supply) are provided by a mix of competitive companies.[142]

Transitioning from a vertically integrated model to a competitive investment model involves foundational restructuring of the electric sector. The primary elements of such state restructuring activities typically includes:

- **Separating the customer bill into distinct components representing each portion of the electricity value chain.** This step clarifies and distinguishes the portions of the customer bill that can be subject to competition (generation investments, energy generation costs), from those that will continue to be subject to traditional regulatory oversight (transmission, distribution, or other state-regulated programs or line items for non-bypassable charges).
- **Identifying a market-based model for attracting competitive supply investments when needed.** The most relevant option for South Carolina would be an RTO-operated regional capacity market, such as those operated by PJM, ISO-NE and NYISO. MISO's capacity market offers some of the same features of these others, but has not (yet) demonstrated capability to attract merchant supply investment when needed.
- **Addressing the ownership arrangements for existing generation supply developed under regulated cost recovery,** to achieve a structurally competitive generation supply segment. Distributing ownership of existing supply resources across multiple generating companies has the effect of ensuring that neither the incumbent utility nor others hold a monopoly share of supply resources, and subjects these players to competitive pressure. Options for addressing ownership arrangements include:
  - **Generation divestiture** is a common strategy used in restructuring states and requires incumbent utilities to sell some or all of their generation assets to competitive generation companies.[143] The advantage of divestiture is that it is the fastest path to full restructuring

[142] For clarity, this discussion omits a substantial amount of complexity and variation in how these segments of industry can interact. For example, some level of competition can be introduced to transmission and distribution, even though they are predominantly regulated as natural monopoly systems. Further, many utilities even in restructured states retain a role in the generation segment through unregulated generation affiliates, by implementing state-directed contracting, implementing state policy programs, or other similar activities. Finally, even in states that rely partly or primarily on a restructured model with competitive investments, the states often exercise their authorities to influence the resource mix through utility-directed or agency-solicited contracts and investments.

[143] Used as a partial or full strategy in many states including California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, New York, Texas, as well as internationally. See discussion in J. Lazar, P. Chernick and W. Marcus, and M. LeBe (Ed.), Electric Cost Allocation for a New Era: A Manual, Regulatory Assistance Project, January 2020 and Reishus Consulting, LLC, Electric Restructuring in New England—A Look Back, prepared for New England States Committee on Electricity (NESCOE), December 2015.

and subjecting all generators to full competitive pressures; the disadvantage is the risk that poorly executed or poorly timed divestitures could sell off assets at below their true value or forfeit long-run customer value that could have been realized.

  - **Retaining utility or government ownership of selected assets,** particularly for assets that have a high (or uncertain) going-forward market value, whose investment costs are already or primarily paid off, or whose future operating/retirement decisions have material policy implications that may not be fully incentivized by market forces alone. For example, existing large hydroelectric and nuclear generation assets with low operating and going-forward costs could continue under utility or government ownership and operation as a means to ensure that full market value (market price minus low resource going-forward costs) can be returned to consumers over the long term.
  - **Asset transfer to an unregulated utility affiliate** is an option that has been used occasionally in which a regulated utility would be allowed to continue to own some or all of the generation assets, but separate them into a different "merchant generation" company affiliate.[144] The state regulator would approve an estimated market value at which the new merchant generation affiliate company could compensate ratepayers for the generation assets. The merchant generation company would then be allowed to operate and collect market revenues associated with the assets for their remaining asset life. The merchant company would be required to be functionally separated from all regulated businesses sufficiently to separately track operating costs and prevent utility self-dealing.[145]

- **Recovering legacy utility investment costs.** At the time of asset divestiture or transfer, proceeds from the sale are returned to customers as an offset to rate base and customer bills. If the proceeds from asset divestiture exceed the remaining asset value in rate base (also referred to as "book value," or remaining undepreciated investment costs that the utility has not yet recovered from customers), then the additional value arises on the customer bill as a discount or credit on the bill for a determined period. If proceeds from divestiture are below remaining book value, the remaining stranded asset cost is passed to customers as a

[144] This option was utilized to some extent in Ohio, Pennsylvania, New Jersey, and Maryland. In these jurisdictions, the distribution utilities' merchant generation affiliates have remained some of the largest generation owners even two decades after restructuring. See J. Lazar, P. Chernick and W. Marcus, and M. LeBe (Ed.), Electric Cost Allocation for a New Era: A Manual, Regulatory Assistance Project, January 2020.

[145] See a discussion of conditions that can give rise to utility self-dealing and options for mitigated potential abuses in M. Harunuzzaman, Ph.D. and K. Costello, State Commission Regulation of Self-Dealing Power Transactions, The National Regulatory Research Institute, NRRI 96-06, January 1996.

"competitive transition charge."[146] States have utilized a wide range of approaches to managing these transition charges, including by allowing securitization (as discussed in more detail in the following section) or amortizing costs over a pre-determined transition period.

POTENTIAL ADVANTAGES

The potential advantages of transitioning toward competitive supply investments include:

- Shift investment, siting, and construction risks from consumers to private companies.
- Use of competitive pressures and profit incentive to drive sector innovation, attract more suppliers, and reduce costs.
- Enhanced ability to attract low-cost resources from third-party suppliers, including demand response, uprates to existing assets, industrial cogeneration, imports, or other unique opportunities not typically available or visible to single utility.
- Full divestiture (rather than partial divesture or asset transfer to a merchant affiliate) offers the fastest pathway to a fully competitive generation segment.
- Partial divestiture can be used to segment generation assets between those that are attractive to divest versus retain under utility or government ownership.

POTENTIAL DISADVANTAGES

The potential disadvantages of transitioning toward competitive supply investments include:

- If transition is completed without an adequate market-based system for attracting competitive supply investment when needed (such as a well-functioning capacity market), then insufficient future supply investments could be made to meet reliability needs.
- Poorly executed or poorly timed asset divestiture poses risk that customers may recover less than the full long-term value of the assets in question.
- Use of asset transfer to a new merchant utility affiliate risks under-valuation of asset value (not subject to full competitive test of potential asset value) and may create future incentives for utility self-dealing or preferential access with the affiliated merchant generation company.

[146] For example, see Pennsylvania utilized such a competitive transition charge to keep utilities whole for stranded investments as of the time of sector restructuring. See 66 PA Cons Stat § 2808 (2016), For a comprehensive discussion of stranded costs in restructuring, see Congressional Budget Office, Electric Utilities: Deregulation and Stranded Costs, CBO Paper, October 1998.

- Under the full divestiture approach, a large portion of utilities' present scope of business and future opportunities for revenue and profits would be curtailed (though investors would be made whole for all investments made to date).
- Potential for cost shifting among customer classes, depending on how any stranded asset costs are allocated.

BENEFIT-COST ASSESSMENT OF TRANSITION TO PARTIAL OR FULL RELIANCE ON COMPETITIVE SUPPLY INVESTMENTS

To examine the potential scale of benefits that could be achieved from competitive investment reforms, we developed an indicative calculation of future resource investment costs under a range of scenarios and sensitivity assumptions. The primary assumption underlying this analysis is that the introduction of competitive investment reforms is implemented in a fashion that follows best practice for maximizing competition in a resource-neutral fashion, appropriately manages transition risks, and hence achieves the theoretical benefits. Due to this and as discussed above, we use the PJM capacity market as an example.

The additional cost savings that arise from having access to a market include: (a) the ability to sell net capacity surpluses into the market thus offsetting customer costs; (b) ability to access cheaper capacity due to market competition; (c) ability to attract new low-cost capacity resources such as demand response and uprates that may otherwise not be identified; and (d) the ability to right-size capacity holdings every year more easily through market purchases instead of new-builds.

The three scenarios we compare include:

- **Status Quo:** In this scenario, we assume that future supply investments continue to be made under the IRP model. The quantity of new resource investments that will be needed also is consistent with the most recent utility IRP peak load forecasts, load growth, and assumes that utilities will maintain reserve margins consistent with minimum reliability requirements in order to manage year-to-year supply-demand uncertainties (this range is consistent with historical resource planning levels).[147]
- **Incremental Participation:** In this scenario, we assume that utility IRP continues as under the Status Quo paired with an incremental participation in the capacity market. In this scenario

[147] See Duke Energy Carolinas South Carolina, 2022 Integrated Resource Plan Update, 2022; Duke Energy Progress, 2020 Integrated Resource Plan Modified, 2020; Dominion Energy South Carolina, Inc., 2023 Integrated Resource Plan, January 30, 2023; Santee Cooper, 2020 Integrated Resource Plan, December 23, 2020.

the total quantity of supply investments needed in the future is reduced due to the load diversity benefits of a regional RTO as explained in Section II.G above. In addition, the utilities are assumed to use the RTO capacity market to balance and "right size" supply needs. Supply excesses can be sold into the market at the market price and the associated revenues returned to customers as an offset to capacity investment costs.[148] Similarly, any supply deficits could be procured from the RTO market at the market price.

- **Full Participation:** In this scenario, we assume that future resources are developed fully under a competitive supply investment model and no new IRP-based, regulated-utility investments are made. In this scenario, capacity needs are procured and any capacity surplus are sold in the PJM capacity market at the market price.

To provide ranges for these three scenarios we developed a Reference Case, High Case, and Low Case, as shown in more detail in Appendix B. We compare the Incremental and Full Participation reform scenarios to the Status Quo and report net benefits. These two reform scenarios are the same in the initial years (2023–2029) because legacy investments have already been made regardless of how South Carolina decides to participate in the capacity market in the future and the scenarios diverge in the later years (2030 onward) once new build capacity is needed. The resulting range of benefits of participating in an RTO with a competitive regional capacity market are presented in Figure 16 below.

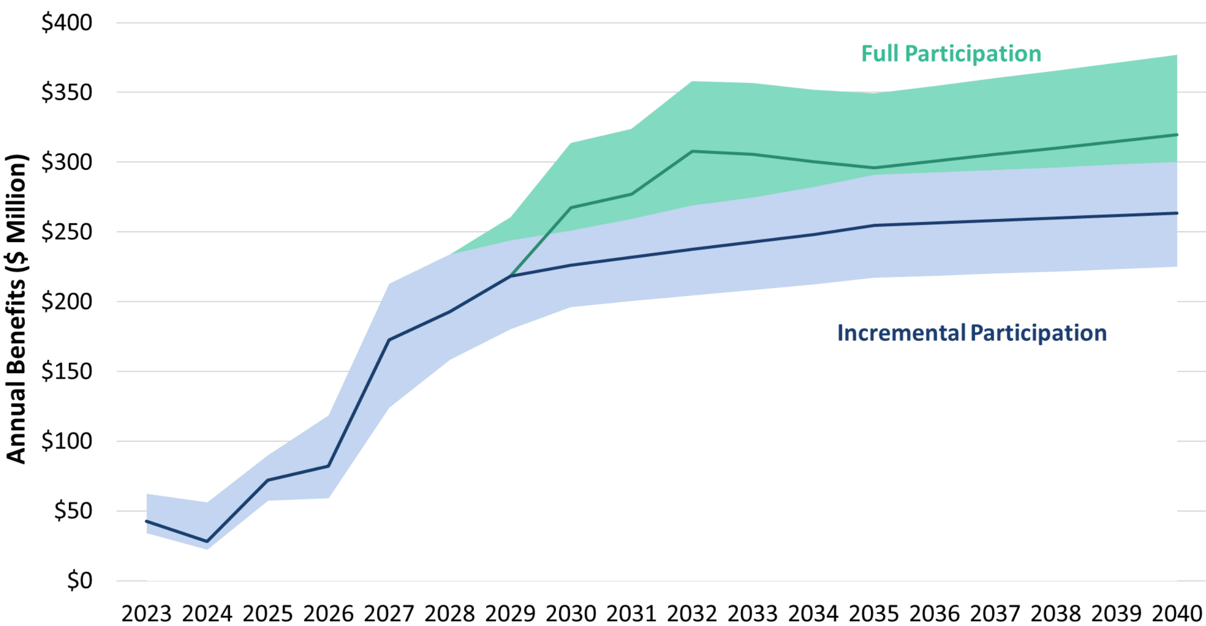
As illustrated in the figure, a portion of the benefits of participating in a regional capacity market would be achieved immediately upon integration and would be realized even if the state continues to rely fundamentally on utility IRP to drive future resource investments. These immediate savings on the order of $25–$120 million/year are those experienced in the first few years (2023–2025) upon joining with an RTO and arise from: (a) the reduction of associated capacity requirements that can be achieved within a pooled resource adequacy framework due to load diversity; and (b) from the ability to collect revenues from selling any surplus capacity to others at the regional market price. These benefits would be achieved immediately and would persist in a similar magnitude for all years into the future (subject to year-to-year variability).

In addition, South Carolina would be able to achieve future benefits if relying on the regional capacity market to attract future supply investments at a lower price than could be achieved through the IRP model. The scale of these benefits grows over time as the proportion of supply

[148] An illustrative range of low to high PJM capacity prices is used to consider both near-term prices that are relatively low and have already established in PJM's forward auctions, with prices rising to PJM's estimated cost of new entry or cost to build new resources over a timeframe of 2025–2040. See Appendix B for more details.

under regulated cost recovery declines with resource turnover, and the proportion of competitive supply investments increases to fill the capacity need. The greatest benefits will be achieved if many third-party suppliers can identify low-cost incremental supply opportunities that would not have been considered within the Status Quo. If substantial volumes of such opportunities exist, they will be developed even while capacity market prices remain low and customer savings will be greatest. If market-based purchases are only available at higher prices approaching or equal to those available under a utility IRP model, then the benefits of transition to a competitive investment model would be lower. Long-term savings are on the order of $150–$300 million/year for the Incremental Participation scenario and $150–$370 million/year for the Full Participation scenario.

FIGURE 16: INDICATIVE RANGE OF POTENTIAL BENEFITS FOR SOUTH CAROLINA FROM COMPETITIVE INVESTMENT REFORMS (REPORTED IN NOMINAL U.S. DOLLARS)



Sources/Notes: Reported in nominal U.S. dollars.

The scenarios we examine here offer indicative bookends to illustrate the scale of potential benefits, including the high end of benefits from a best practice implementation toward full reliance on a competitive investment model. Other more incremental reforms, such as introduction of competitive procurement to utility IRP, could be expected to achieve a portion of these potential benefits commensurate with the smaller scope and scale of competition achieved. For additional details, see Appendix B.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

If South Carolina determines that the policy of the state is to shift toward a competitive investment model, we recommend that this policy intention could be signaled today but that the implementation should be staged in a measured fashion to mitigate transition risks. The stages of implementation would involve:

- First, joining or creating an RTO market with a requirement that the market include a viable model for attracting competitive capacity supply investments when needed. Even if utility or state-overseen IRPs are used to secure some or most of all supply investments going forward, a viable market-based resource adequacy and investment model would be needed to attract the residual needs.
- Second, if South Carolina were to consider retail access, then establish a coordinated plan and timeframe for the introduction of partial or full retail competition that approximately aligns with the timeframe for transitioning to reliance on competitive supply investments.
- Third, if South Carolina were to consider unbundling and deregulating generation, then for each affected utility, develop a timeline and oversight plan for determining the timeframe and format for (partial) asset divestiture, considering that some assets may be attractive to retain under utility or state ownership for a longer period (e.g., recently-built assets with long outstanding asset lives, large nuclear or hydro facilities with low going-forward cost and high market value). We do not recommend considering transfer of regulated assets to unregulated merchant affiliate companies.
- Fourth, if South Carolina were to consider retail access with a deregulated generation sector, then update rates to separate all segments of the regulated and unregulated business segments, including a distinct line item for the recovery of legacy utility investment costs.

F. Securitization of Costs Related to Retiring Thermal Assets

DESCRIPTION AND RELEVANT CASE STUDIES

Vertically integrated utilities make retirement decisions, under commission oversight, for thermal assets based on a number of economic factors such as going forward costs; fuel and operation costs; capabilities and costs of competing technologies; policy decisions such as environmental regulations and state incentives; as well as the plant age and engineering estimates of remaining useful life. Thermal generation assets owned by a utility can become "impaired" or "stranded" if the plant is no longer expected to provide a net benefit going forward and there remains some undepreciated book value in the rate base that has not yet been recovered from customers. Assets can become impaired or stranded due to changes (or expected changes) in the economic, regulatory, or technological landscape where the utility operates. Many coal assets across the U.S., for example, presently face high going-forward maintenance and operating costs such that they are more costly to continue operating than it would be to retire them and develop or procure replacement supply from lower-cost new gas CC plants, renewables, or market purchases.[149] The public interest is best served by allowing such an impaired coal asset to retire and pursuing cleaner and lower cost replacement resources (even if customers must continue paying down the undepreciated book value after plant retirement). However, not all states have yet formalized processes regarding the regulatory treatment to ensure that impaired assets can be retired when it is economical to do so.

If thermal assets become stranded, there are several options for treating cost recovery of the undepreciated portion of these assets.[150] The first choice before regulators is whether to: (i) allow plants to continue to remain in the rate base and recover their undepreciated book value; (ii) allow utilities to recover undepreciated value outside of the rate base; or (iii) to disallow portions of cost recovery. As shown in Table 14, regulators in various U.S. states have decided to allow retired plants to remain in the rate base as an intangible "regulatory asset" (which may or may not continue to earn the utility's regulated rate of return) or to be allowed to earn the regulated rate of return but over a shorter depreciation schedule.[151] Regulators in some cases

[149] Existing coal generation has been under financial pressure since the shale gas revolution starting in around 2008, exacerbated by increasingly stringent environmental regulations and rapid cost reductions in wind and solar generation. In many cases, the going-forward costs for coal generators has exceeded the annualized costs for replacement generation from new-build alternatives, in which case the efficient solution is to retire the coal plant. Accordingly, between 2012 and 2021, an average of 9,450 MW of U.S. coal-fired capacity was retired each year and 23% of the current coal-fired capacity is planned to retire by the end of 2029.

[150] The term "depreciation" in this context refers to the reduction in the remaining unrecovered capital cost accounted for in the rate base of a regulated utility. This is distinct from the tax depreciation used for calculating taxable income.

[151] Regulatory assets are created when a regulator approves recoverable costs that would increase rates in one period to be implemented at a future time. A regulatory asset is an intangible asset in that the utility has an enforceable present right to increase an amount in the rate base to be charged to customers in future periods. Conversely, a regulatory liability arises when a utility has an enforceable present obligation to deduct an amount in the rate base to be charged to customers in future periods. In the case of early asset retirement, regulators often have allowed the remaining undepreciated value to be recovered as a regulatory asset; see International Financial Reporting Standards Foundation (IFRS) and International Accounting Standards Board (IASB), Regulatory Assets and Regulatory Liabilities, IFRS Standards Exposure Draft ED/2021/1, January 2021; K. Spees and M. O'Loughlin, Stranded Fossil Fuel Infrastructure: How Big Is the Stranded Asset Problem, and What Should We Do About It?, The Brattle Group, June 24, 2021.

have also disallowed cost recovery on portions of the undepreciated asset to the extent that the costs were deemed imprudent. For prudently-incurred costs, utilities and regulators may also examine "securitization" as an alternative financial tool to enable full cost recovery outside of the rate base.[152]

TABLE 14: RECENT EXAMPLES OF REGULATORY TREATMENT OF UNDEPRECIATED THERMAL ASSETS

Treatment	Description	Number of cases (2010-2020)
Rate Based		
Regulatory asset	Plant is retired and utility continues to receive return on and of investment; takes effect upon retirement	20
Accelerated depreciation	Plant's depreciation schedule is changed to match the period until retirement; put in place in anticipation of retirement	7
Not Rate Based		
Securitization	Recovery of stranded assets through ratepayer-backed bonds with low interest rates	3
Partial disallowance	Part of the undepreciated cost or return on that balance is removed	2

Source/Notes: Compiled by Dr. Metin Celebi, The Brattle Group; see K. Spees and M. O'Loughlin, Stranded Fossil Fuel Infrastructure: How Big Is the Stranded Asset Problem, and What Should We Do About It?, The Brattle Group, June 24, 2021.

Securitization is a well-established financial practice employed for a variety of uses in many industries, including several applications for electric utilities. Securitization for thermal generation retirements works by providing strong legal and regulatory assurances for cost recovery of the undepreciated value of a stranded asset in order to enable the utility to issue debt to refinance and recover that value, as depicted in Figure 17. This debt is typically issued as bonds through a Special Purpose Entity (SPE), owned by the parent utility. The bonds are secured by a guarantee (backed by state law and approved by the regulator) that ratepayers will fund repayments through a non-bypassable surcharge on customer bills, which is why they are also sometimes referred to as "ratepayer-backed bonds" or "RBBs." The SPE is considered "bankruptcy-remote" relative to the owning utility, meaning that its financial performance has little economic impact on the parent utility and the debt issued through the ratepayer-backed bonds are nonrecourse to the utility. That is, the issued debt does not draw on the utility's credit

[152] M. Celebi, et al., "Managing Coal Plant Retirements for an Orderly Transition to Decarbonization," The Brattle Group, accessed January 24, 2023.

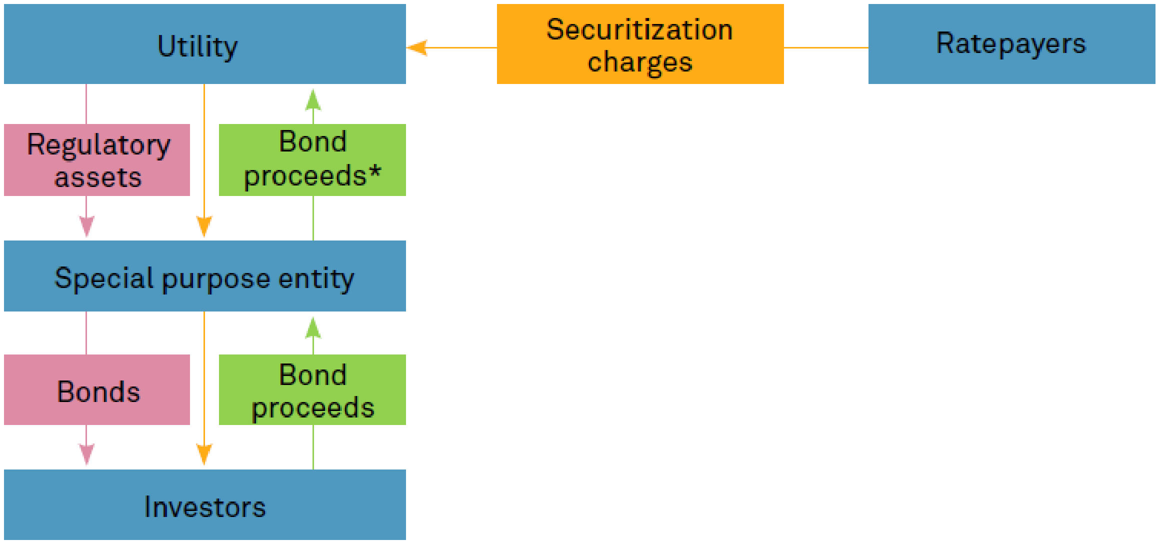
and should not impact its credit rating.[153] The right to receive payments from the non-bypassable surcharge is sold by the utility to the SPE as an intangible asset, which the SPE then pledges as collateral for the issued bonds. These bonds are then sold to investors. In short, the SPE functions to receive payments from customers through the bill surcharge and to repay the bondholders.

The regulator, in addition to allowing the utility to create the customer bill surcharge to guarantee repayment of the bonds, also guarantees that the SPE will be able to repay bondholders in the future on both principal, interest, and any associated issuance costs by allowing the bill surcharge to be periodically adjusted through a "true-up" mechanism without further regulatory review. These guarantees are enabled and codified by state law. Through these various guarantees, securitization bonds are typically able to obtain an AAA credit rating (the highest rating possible and several grades higher than typical U.S. electric utility credit ratings) and therefore can be issued at very low interest rates.[154] This reduced interest rate minimizes the cost to customers of reimbursing the utility's unrecovered stranded cost. Furthermore, securitization is a flexible mechanism that can be designed to alleviate sudden increases in rates, known as "rate shocks."

[153] This is true from the perspective of cash flow to the utility although rating agencies are split on the "on-credit" treatment of securitization; See also J.S. Fichera and R. Klein, Lowering Environmental and Capital Costs with Ratepayer-Backed Bonds, Natural Gas & Electricity Journal, Wiley Periodicals, February 2007.

[154] See J.S Fichera, Managing Electricity Rates Amidst Increasing Capital Expenditures: Is Securitization the Right Tool? An Update, National Regulatory Research Institute (NRRI) Insights, January, 2019 and Edison Electric Institute (EEI), 2021 Financial Review, Annual Report of the U.S. Investor-Owned Electric Utility Industry, Credit Ratings, 2021.

FIGURE 17: SECURITIZATION FLOW DIAGRAM



Sources/Notes: S&P Global Market Intelligence, LLC, "A variety of stranded cost recovery abatement strategies emerging in US energy transition", Regulatory Research Associates Regulatory Focus, Topical Special Report, December 6, 2021.

Through securitization, customers stop paying the utility's cost of capital on the remaining asset, and instead begin paying for the asset through the bill surcharge at the lowest possible interest rate. Securitization also provides tax savings for the utility that can be further passed to customers through rates. When properly designed, securitization can lower customer bills compared to allowing the stranded asset to remain in the rate base and subject to the higher utility return.

Securitization has been implemented in many use cases in the electric sector, and increasingly is being considered in the context of thermal plant retirements. In 2016, Duke Energy Florida was approved to issue $1.3 billion in securitized bonds related to stranded costs from retiring the Crystal River nuclear plant.[155] Compared to full cost recovery at the approved utility rate of return, securitization was estimated to reduce customer costs by approximately $700 million over 20 years.[156] In 2020, the Michigan Public Service Commission approved Consumer Energy Michigan's application for securitization bonds of up to $678 million due to the closure of two coal plants that was estimated to lower the cost of making the utility whole by around $126

155 U.S. Securities Exchange Commission (SEC), $1,294,290,000 Series A Senior Secured Bonds, Preliminary Prospectus, Dated June 15, 2016, Duke Energy Florida, LLC.

156 North Carolina Energy Regulatory Process (NERP) Securitization Study Group, Securitization for Generation Asset Retirement, Study Group Work Products, December 18, 2020.

million.[157] Also in 2020, the New Mexico Public Regulation Commission approved securitization bonds of up to $360 million of unrecovered investments due to the abandonment of the San Juan coal plant units 1 and 4.[158] The Public Service Company of New Mexico (PNM) estimated the net bill impact of the securitization and replacement resources would be a savings of $5.93/month per residential customer using an average of 600 kWh per month in 2023, other estimates have quoted approximately $6.67/month in bill savings for an average customer.[159]

Securitization has also been used as a method to recover costs incurred during extenuating circumstances, such as to recover damages from storms and other extreme weather.[160] South Carolina has also enabled securitization for recovery of storm damages.[161] In total, eight states have securitized $6.2 billion in relation to storm damages.[162] Additionally, securitization has been used to fund conservation programs, green investments, environmental compliance measures, company reorganizations, reliability expenditures, impacts from the Covid-19 pandemic, and most notably, costs arising from the transition to enabling retail competition in the 1990's and early 2000's as shown in Figure 18.

[157] Michigan Public Service Commission (MPSC), Press Release, "MPSC OKs securitization bonds for Consumers Energy as utility prepares for 2023 retirement of coal-fired generating units," December 17, 2020.

[158] The Brattle Group, "Unanimous NMPRC Decision for PNM to Abandon San Juan Coal Plant Relies on Expert Testimony by Principal Frank Graves," April 13, 2020.

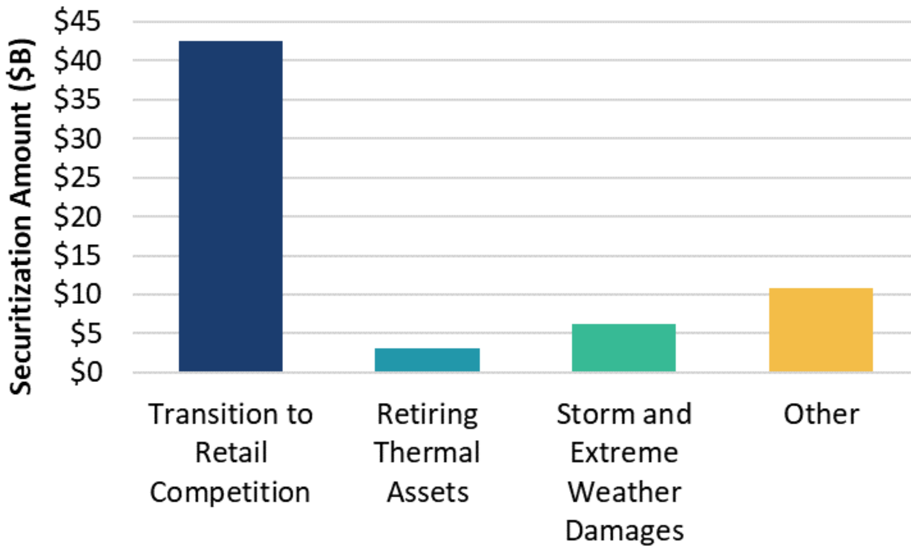
[159] Public Service Company of New Mexico (PNM), Consolidated Application for the Abandonment, Financing and Replacement of the San Juan Generating Station Pursuant to the Energy Transition Act, Before the New Mexico Public Regulation Commission, July 19, 2019; San Juan Citizen's Alliance, "San Juan Generating Station cleared for abandonment by PRC," April 1, 2020.

[160] North Carolina Energy Regulatory Process (NERP) Securitization Study Group, Securitization for Generation Asset Retirement, Study Group Work Products, December 18, 2020.

[161] South Carolina Act No. 227, Effective date June 17, 2022.

[162] These states are: Arkansas, Florida, Kansas, Louisiana, Mississippi, North Carolina, Oklahoma, and Texas; see S&P Global Market Intelligence, LLC, Overview of utility use of securitization in the U.S. by category, Regulatory Research Associates, data gathered as of June 25, 2021.

FIGURE 18: 2021 SECURITIZATION AMOUNTS IN THE U.S. BY USE CASE



Sources/Notes: Nominal U.S. dollars. S&P Global Market Intelligence, LLC, Overview of utility use of securitization in the U.S. by category, Regulatory Research Associates, data gathered as of June 25, 2021.

POTENTIAL ADVANTAGES

The potential advantages of considering securitization as an option for enabling thermal retirements include:

- Can facilitate retirement of stranded thermal assets and enable them to be replaced with lower-cost and cleaner resources.
- Reduces the cost for customers to make the utility whole for prudently-incurred costs.
- Allows utilities to raise new funds for redeployment into newer technology and lowers borrowing costs to enable greater balance sheet flexibility.

POTENTIAL DISADVANTAGES

The potential disadvantages of considering securitization as an option for enabling thermal retirements include:

- Estimates of stranded costs are variable and dependent on assumptions of future conditions; regulators could pre-commit to compensating an amount that exceeds utilities' actual costs with no ability to adjust once decided.
- Since ratepayer-backed bonds are typically exempt from state income tax, some of the cost burden of stranded costs is shifted from ratepayers onto taxpayers.

- Potential to increase borrowing costs for municipalities since securitized bonds (due to their income-tax free status and high credit rating) compete directly with municipal bonds.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

With the passage of Act No. 227 ("Act 227"), South Carolina has existing law allowing for securitization for storm damages recovery. Therefore, existing legislation could be adapted to explicitly enable securitization as one option for regulatory treatment of retiring thermal assets as well. If adopting such legislation, we recommend that it should authorize the PSC to enable plant retirements through securitization when deemed in the public interest. To address any potentially stranded asset costs, the PSC could be authorized to consider all potentially relevant cost recovery mechanisms for prudent retirement decisions, including traditional cost recovery (beyond the planned retirement date), accelerated depreciation, and securitization. We note that the regulator needs to play an active role to ensure that the interests of ratepayers, taxpayers, utilities, members in the local economy impacted by the plant closure, and potential investors are all balanced to achieve the greatest benefits when considering securitization.

G. Recommendations for Supply Investment Reforms

Based on our assessment of potential supply investment reform options, we recommend that South Carolina policymakers consider the following options. We note that many of these reform options are complementary to each other (not mutually exclusive alternatives). We recommend that South Carolina:

- **Join an RTO that ensures resource adequacy (accounting and enforcement) over a larger, more diverse footprint**. This step would yield immediate cost savings by reducing reserve capacity requirements for South Carolina utilities, by enabling the utilities to more cost-effectively manage temporary surpluses and deficits in their resource plans, and by easing the logistics of major plant retirements. If South Carolina additionally wanted to create the option to transition to a model that is partly or fully reliant on competitive generation investments in the future, we recommend prioritizing consideration of an RTO with a track record of attracting competitive generation investments.
- **Authorize the PSC or other state agencies to consider or conduct statewide IRP processes,** if the PSC identifies a benefit to conducting such an exercise, either to achieve cross-utility coordination benefits, better inform policy choices on a statewide

basis, or provide statewide needs assessments for the purpose of competitive solicitations. The option for an agency-overseen statewide IRP could be utilized either on an ad hoc basis when a specific need is identified, or could be incorporated into regularized IRP processes.

- **Incrementally introduce and expand the role of competitive solicitations within utility and/or state IRP processes**. South Carolina is presently gaining more experience with competitive renewable and all-source solicitations, which (along with experience in other states) can inform the most advantageous oversight and procurement model. Further expanding the role of competitive solicitations can be achieved via options such as: (a) requiring (rather than "allowing" as is done currently) future supply needs identified in IRPs to be met through all-source competitive solicitations; (b) designing competitive solicitations that will consider utility self-build projects alongside IPP projects, authorizing state agencies to rely on an independent evaluator to conduct the process and recommend winning projects to the PSC for approval; (c) enabling cooperative and municipally owned utilities to participate in state agency or utility-specific procurements, allowing them the option (but not the obligation) to procure a share of selected resources; and (d) (after joining an RTO) considering the option for reliance on regional markets for providing a defined portion of IRP-identified supply needs.
- **Confirm or clarify regulatory policies related to the retirement of uneconomic aging resources** to ensure that utilities have the ability and incentive to retire aging generating assets when other lower-cost supply options become available. In determining the most beneficial outcomes for ratepayers, authorize the PSC to utilize all potentially relevant cost recovery mechanisms for prudent retirement decisions, including traditional cost recovery (beyond the planned retirement date), accelerated depreciation, and securitization.
- **Consider additional competitive investment reforms in the future.** After gaining experience with RTO market participation, competitive IRP-based procurement processes, and retail market reforms (discussed below), reassess the question of competitive investment reforms to determine whether further transition to competitive investments is desired. If so, consider utilizing a graduated transition path that would rely increasingly on competitive generation investments over time as demand increases, existing resources retire, and existing contracts expire.

IV. Retail Market Reforms

A. Overview of Potential Retail Market Reforms

Currently in South Carolina, vertically integrated utilities are responsible to serve the supply needs of customers within their respective service territories. In the retail sector, this means that utilities own, operate, and maintain the distribution system, administer metering services, ensure procurement or production of power to serve customers, and ensure generated electricity is delivered to customers.

Retail market reforms focus on the question of whether and how customers can choose to procure power from alternative resources or providers of retail electricity as shown in Figure 19. Some resource choice can be achieved by offering advanced retail rate structures, however by enabling customers to select a retailer (a private company that procures power for customers) instead of limiting their supply choice to the incumbent utility), competitive retail markets empower customers to negotiate rates and service offerings through competition among retail suppliers.[163] A competitive retail market would allow customers to better pursue their own preferences with regards to: (i) rate structures (both level and stability); (ii) environmental goals; (iii) supply resource type or locally/community-sourced supply; (vi) communicating billing information and other items with the customer (e.g., traditional mail, app-based, email-based, direct device control); or (v) other innovative types of retail services (e.g., electric vehicle charging or vehicle-to-grid management, demand response programs, bundled electric and gas or other services, distributed solar/battery management, electric and non-electric smart home device management). The retail market reforms we examine in this study include:

- **Utility retail rate reforms to offer additional customer choices** that would authorize or require utilities to design more efficient or advanced retail rates structures.
- Enabling **partial retail choice** for large C&I customers, so that these customers have the ability to seek self-supply or contract with a third-party electricity supplier.

[163] Even if retail competition were introduced, the distribution utility's role in the retail sector as the distribution system planner and owner would continue. The costs of the distribution system would continue to be passed to the retail customer as a non-bypassable charge, even if an alternative retail provider takes over customer billing, customer service, and competes on price/rates relative to all competitively-set line items on the customer bill (that can include energy supply as sourced bilaterally or through RTO markets, investment costs associated with energy supply, and other retail services that may be provided).

- Enabling **full retail choice** including residential and small business customers, to offer the same benefits of competitive retail markets and alternative suppliers to small customers.
- Enabling **Community Choice Aggregation (CCA)** to allow communities (even those not served by a municipally owned utility) to select a third-party supplier of retail electric service.
- **Competitive reforms to enable distributed energy resources,** to create opportunities to incentivize and leverage third-party DR and DER providers.
- Establishing a **third party energy efficiency administrator** to regularize and expand energy efficiency (EE) programs that are cost-beneficial to customers but that have not been fully developed under existing structures.

South Carolina can implement these reforms under state authorities without any cooperation or coordination with other states. While not strictly necessary for most of these reforms, the benefits of retail market reforms are greatly enhanced when paired with a regional wholesale market.

FIGURE 19: POTENTIAL ROLE OF RETAIL MARKET REFORMS IN SOUTH CAROLINA

	Generation	Transmission	Distribution	Retail Customers
Status Quo: **Vertically Integrated Utility**	**Resource Operations** • Utility: Manages generation & transmission scheduling **Supply Investments** • Utility: Conducts integrated planning. Builds and owns resources	**Interregional Energy Trade** • Utilities: Manages generation & transmission scheduling • SEEM: Utilities run & participate in SEEM, to support enhanced bilateral trade **Transmission System** • Utility: Plans & builds bulk transmission	**Distribution System** • Utility: Plans & builds distribution system	**Customer Deliveries** • Utility: Sources all electricity supply and bills customers for associated cost
Retail Market Reforms				**Customer Deliveries** • Customers: Select retail provider to procure needed supply (compete on price, green, or other values)

Source/Notes: This figure illustrates which roles in each section of the electricity value chain are changed by each area of reform. Blank areas indicate where there are no or minimal changes to the existing industry structure under a given reform area.

B. Status Quo with Exclusive Utility Service for Retail Supply

DESCRIPTION OF STATUS QUO IN SOUTH CAROLINA

Under the vertically integrated utility model, retail functions include owning, operating, and maintaining the distribution system, ensuring procurement or production of power to serve customers, providing metering services, and ensuring generated electricity is delivered to customers. Utilities plan for distribution system investments, and the PSC approves distribution system capital investments and operation plans for large utilities, and sets the retail rates large utilities use to recover these investment and operation costs. Retail rates therefore include distribution and retail service costs, which are bundled with generation and transmission costs (as discussed in prior sections). The IOUs in South Carolina (Duke and Dominion) as well as the state-owned utility (Santee Cooper) directly serve customers in their territories but also supply wholesale services to electric cooperatives and municipal utilities, who then serve retail customers.[164]

A central element of the status quo for the retail sector is that the various distribution utilities are granted the exclusive right to provide bundled service to customers within their respective territories. PSC oversight seeks to manage costs and ensure that rates charged to customers by large utilities are set at fair levels in alignment with prudently incurred utility costs. Customers dissatisfied with their rates or other aspects of utility service are not able to seek alternative sources of electricity supply.

ADVANTAGES OF STATUS QUO APPROACH

Advantages of the status quo include:

- Customers enjoy price stability as most investment costs are recovered over a long period
- Retail rates and utility investment choices subject to state oversight

DISADVANTAGES OF STATUS QUO APPROACH

Disadvantages of the status quo include:

- Investment and fuel price risks borne by customers under cost-of-service regulation
- Customers have limited retail service options and are unable to negotiate, switch providers, or pursue self-supply if unsatisfied with service or resource mix

C. Retail Rate Reforms to Offer Additional Customer Choices

DESCRIPTION AND RELEVANT CASE STUDIES

A wide array of innovative rate structures have been, and can be, used to increasingly improve the customer choices and value of electric service (even if other retail reform options are not implemented). We review here a subset of potential rate design reforms that generally seek to offer more economically efficient rates, activate demand response and DERs to provide grid services, enable more opportunities to select green supply, and improve utilities' incentives to

[164] For example, Central Electric Cooperative is a customer of Santee Cooper and Duke, and supplies its 20-member cooperatives with wholesale services. The individual member cooperatives then directly serve customers.

reduce costs. Some of these rate options are already under consideration or in use within South Carolina (we do not attempt to compare all South Carolina utilities' rates relative to these options for the purposes of this study.)[165]

Cost-causation is a fundamental principle underlying economically efficient and effective rate design, meaning that electricity pricing should reflect the economic cost of providing electricity to customers.[166] Cost-based rates should lead to improvements in equity and fairness in cost recovery by removing unintended subsidies embedded in the rate design. When designed well, cost-based retail rates contribute to reduced distribution costs in the long run by encouraging customers to use electricity more efficiently.[167]

Time-varying rates are a category of rates that seek to provide economically efficient price signals to customers, demand response providers, and DERs to behave and operate in ways that improve the overall cost effectiveness of the system and reduce total system costs. Customers and distributed resources reacting to such rates can change their consumption profiles or net production profiles in ways that reduce total system costs, as long as their retail rate offers an accurate incentive to do so. Several categories of time-varying rates include:

- **Time-of-use (TOU)** rates charge customers a higher price during an established peak period and a lower price during one or more off-peak periods.[168] While traditional TOU rates have been offered for decades, TOU rate design recently has experienced renewed interest as an element of net energy metering (NEM) reform, as well as a tool for encouraging off-peak charging of electric vehicles (EVs) or for incentivizing load shifting to hours with excess solar output. For example, some utilities and state regulators have begun to deploy TOU rates as the default rate option for residential customers.[169]
- **Critical peak pricing (CPP)** is a form of dynamic pricing, with a peak period price that can be implemented selectively on days with significant capacity constraints. CPP events can be called to reflect capacity constraints at the bulk system level, or to manage local distribution

165 Many new retail rate structures have been enabled in the South Carolina Energy Freedom Act which has provisions for Net-Energy Metering, access to residential and community solar, "solar choice" TOU rates, among others. South Carolina Act No. 62, "SC Energy Freedom Act," effective date May 16, 2019.

166 A. Faruqui, et al., Modernizing Distribution Rate Design, The Brattle Group, prepared for ATCO, March 13, 2020.

167 A. Faruqui, et al., Modernizing Distribution Rate Design, The Brattle Group, prepared for ATCO, March 13, 2020.

168 A. Faruqui, et al., A Survey of Residential Time-Of-Use (TOU) Rates, The Brattle Group, November 12, 2019.

169 A. Faruqui and R. Hledik, Smart by Default, The Brattle Group, Fortnightly Magazine, August 2014.

system constraints.[170] Thus far, CPP rates largely have been implemented through participation-limited pilots, through interest in deploying them on a full-scale basis to encourage load flexibility is growing in some jurisdictions.[171]

- **Peak time rebates (PTR)** are similar to CPP rates in the sense that they include an event-based demand signal. However, unlike CPP, PTR provides customers with the incentive to reduce peak usage through a rebate payment for all kilowatt-hours of usage reduced below an estimate of their baseline usage during the event. Generally, utilities and regulators have been more willing to deploy PTR to customers on a default basis than CPP because PTR is a no-lose proposition for participants; meaning there is no risk that their bill will increase as a result of enrolling. However, a challenge of PTR implementation is estimating the customer's baseline usage and the risk of free-ridership.
- **Residential capacity/demand based retail rates** bill customers for their maximum demand over a billing cycle, often as measured over all hours of the cycle but sometimes only measured during hours of a peak coincident window (e.g., 2 pm to 6 pm).[172] While demand charges have been a common rate design feature for larger customers, they are much less common for residential customers. However, demand charges have recently emerged as an option for improving recovery of fixed costs from residential customers without the potentially regressive impacts of significantly increasing fixed charges.[173]

Green tariffs and green pricing programs have been implemented in states with vertically integrated utility models, where customer options for accessing renewable resources are expanding through "green tariff" and/or "green pricing" programs.[174] Green Tariffs/Pricing programs have emerged recently as an option offered by utilities to enable customers to procure up to 100% of their electricity from clean sources at a fixed or predictable price. With green tariffs, customers pay a premium to ensure that some or all of their electricity consumption is covered by carbon-free generation. That clean energy can come in the form of Renewable Energy Credit

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[170] A. Faruqui and R. Hledik, Time-Varying and Dynamic Rate Design, The Brattle Group, Regulatory Assistance Project, Global Power Best Practice Series, July 2012.

[171] A. Faruqui and S. Sergici, Arcturus 2.0: A Meta-analysis of Time-varying Rates for Electricity, The Brattle Group, published in The Electricity Journal, Volume 30, Issue 10, December 2017, pp. 64–72.

[172] R. Hledik, Rediscovering Residential Demand Charges, published in The Electricity Journal, Volume 27, Issue 7, September 2014, pp. 82–96

[173] R. Hledik and A. Faruqui, Competing Perspectives on Demand Charges, The Brattle Group, published in Public Utilities Fortnightly, September 2016.

[174] National Renewable Energy Laboratory (NREL), Status and Trends in the Voluntary Market (2020 data), September 29, 2021.

(REC) purchases or funding a new utility renewables project, for example. In practice there are three kinds of Green Tariffs that have developed: Sleeved PPAs, Subscription Programs, and Market-based Rates (MBR).[175]

- **Sleeved PPAs** are so called because the customer negotiates with the utility to dedicate a new or existing renewable energy facility to meet all or a significant portion of the customer's load. The utility acts as an intermediary on behalf of the interested customer and signs a PPA with a renewable developer. The PPA is then "sleeved" through the utility to give customers access to the clean energy procured with the PPA, and customers are charged for the costs of the renewable power and development charges over and above the base utility rate. Contract length minimums are usually longer (two years or more) since the customer contracts a dedicated renewable resource for their consumption and typically has an input to project location and technology type.
- **Subscription programs** are another way customers can access clean energy. In this approach the utility either signs a PPA with a renewable developer or develops and owns the renewable project. The main difference is now the utility either works with the renewable developer or fully determines the resource type and location. The customer pays a fixed price for renewable energy and retail service, and also gets credited for any excess supply the renewable resource generates. Contract lengths are typically shorter and sold in MW blocks. Subscription pricing has also been implemented to contribute to a variety of environmental and policy goals, such as energy efficiency, demand response, or clean energy subscriptions.[176]
- **Market-based rates** work by having the utility allow customers to contract with a renewable developer within an ISO or RTO territory. The customer is then charged a fixed price for renewable energy based on the market rate and (if the customer has onsite DERs) can sell energy and RECs into the market. Contract lengths are typically one year or longer.

Green Tariffs have seen some success in attracting corporate buyers of clean energy. In 2016, Facebook announced its decision to open a new data center in New Mexico. This decision was made in part because the Public Service Company of New Mexico (PNM) created the state's first green tariff program to enable Facebook to supply 100% of its energy needs from renewable

[175] S. Sergici, Accelerating the Renewable Energy Transformation, The Brattle Group, presented to the EUCI Southeast Clean Power Summit, February 25, 2019.

[176] P. Fox Penner et al., FixedBill+ Making Rate Design Innovation Work for Consumers, Electricity Providers, and the Environment, The Brattle Group and Energy Impact Partners (EIP), Working Paper, June 2020.

generation.[177] The data center has since garnered capital investment of over $2.2 billion in the state.[178] In South Carolina, Duke Energy has recently had the Green Source Advantage program approved by the PSC, which consists of a total capacity of 200 MW of new renewable energy available to large customers.[179] Similarly, Dominion has proposed a Voluntary Renewable Energy Rider program for 135 MW for large customers.[180]

POTENTIAL ADVANTAGES

The potential advantages of pursuing options for new retail services and rate designs depend on the type of rate reforms in question and the underlying improvement they seek to achieve. Benefits generally include:

- Improved economic efficiency, with more efficient price signals embedded in the retail rate structure in line with economic principles of cost causation.
- Time-varying rates can provide customers with better incentives against which to manage consumption levels, consumption profiles, and activate DR/DER assets. Customers taking advantage of such rates can reduce their own bills at the same time as producing system-wide cost savings.
- Green tariffs and similar options can provide customers with opportunities to access clean energy resources in alignment with their own environmental and sustainability goals.

POTENTIAL DISADVANTAGES

Pursuing alternative retail services and rate design options has minimal disadvantages, as long as the new rates are reviewed and implemented with sufficient care to ensure that they enhance economic efficiency, improve customer choice, and follow the key principle of cost causation.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

Many of these potential advances in rate design may already be possible to pursue under existing law (and some are already in use by several utilities). If South Carolina wished to expand the use

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177 Sanem Sergici, Accelerating the Renewable Energy Transformation, The Brattle Group, presented to the EUCI Southeast Clean Power Summit, February 25, 2019.

178 The Tech Capital, "Meta raises Facebook Los Lunas data centre investment to $2.2bn," November 1, 2022, accessed February 2, 2023.

179 Duke Energy, "Green Source Advantage offers more renewable energy options for South Carolina customers," February 23, 2021

180 Dominion Energy South Carolina, Inc., Rider to Retail Rates: Voluntary Renewable Energy ("VRE") Rider for Renewable Generation ("RG") Supply Agreements, July 26, 2021.

of potentially beneficial rate-making options, the legislature could explicitly authorize (and perhaps require) the PSC and regulated utilities to evaluate options for expanded and enhanced retail rate choices for South Carolina customers, such as increasingly advanced time-varying rates seeking to activate new DR/DER technologies, expanding green tariffs and related green energy options, and rate designs to enhance efficiency.

D. Partial or Full Retail Choice

DESCRIPTION AND RELEVANT CASE STUDIES

From the mid-1990s through the early 2000s, several states restructured their electric markets to allow for retail choice. "Retail choice" refers to enabling consumers to procure their electricity from a variety of competitive retailers that provide their customers with electricity service by purchasing electricity from the wholesale RTO market, through self-supply, or through bilateral contracts. While retailers purchase power on behalf of their customers, they deliver the power across transmission and distribution lines that continue to be owned and operated by the incumbent utility. Customers that do not choose to receive service from a third-party supplier will continue to be served under a rate-regulated option that may or may not be provided by the incumbent utility.

States that have implemented retail choice can be classified as either full or partial retail choice depending on whether the ability to procure electricity from competitive suppliers is limited to certain customer types (typically large C&I consumers) or enabled for all customers (including small businesses and residential consumers). Nearly all retail choice programs are voluntary and function on an opt-in basis. Customers under opt-in retail choice that do not choose to participate in the retail market are assigned a designated default service, sometimes called Standard Offer Service, Basic Generation Service, Provider of Last Resort (POLR), Price to Beat, or PUC Offer.[181] Standard offer service rates are developed under commission oversight for IOUs, and reflect a regulator-approved method for developing retail rates as a function of wholesale electricity prices, including utilizing a level of price hedging deemed appropriate by the regulator. A typical approach is to auction off the right to provide standard offer service in 2–3 year intervals, auctioning a slice-of-system in each auction and relative to the realized profile of the aggregate pool of customers being served. Potential providers of the retail service compete to offer the price hedge at the lowest cost (considering their own assessment of wholesale market risks and their own ability to self-supply or contract).

[181] F. Graves, et al., Retail Choice: Ripe for Reform?, The Brattle Group, July 2018.

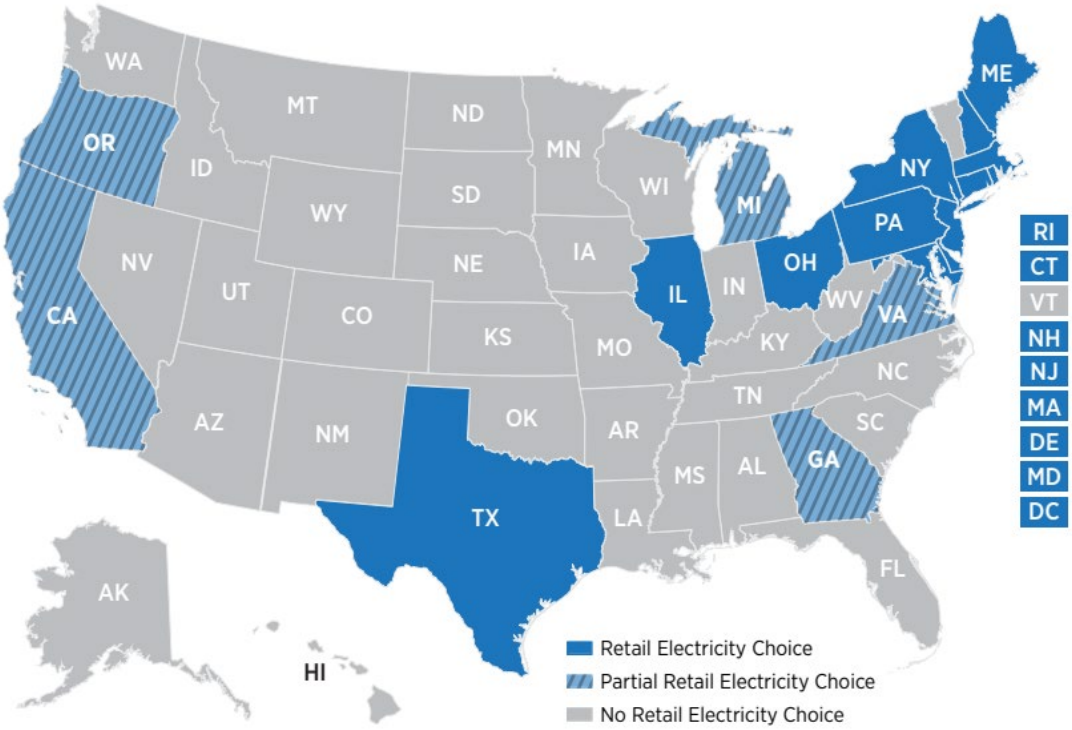
A wholesale market (such as an RTO) is a highly valuable (though not strictly required) precondition for introducing effective retail choice. A wholesale market allows for a much clearer energy price signal and price to beat, enabling clarity in the unbundling of generation services from transmission/distribution services to enable product differentiation and extract meaningful benefits for retail customers.

Currently, 18 states and the District of Columbia have active, statewide residential retail choice programs (see Figure 20 below). Five of the 18 states—Georgia, Virginia, Michigan, California, and Oregon—have partial retail choice that is mostly available to large C&I customers in certain jurisdictions within the state. Typically, retail choice (and the subsequent retail markets) form in states that already have wholesale markets; however, there are notable exceptions such as Georgia, which has enabled partial retail choice for large C&I customers but is not part of an RTO. Of the states that have retail choice, between 10%–50% of residential and 65%–90% of C&I total eligible load exercised their right to switch to competitive retail providers in 2018.[182] Outside of Texas, Ohio has the highest number of residential retail choice customers, followed by Illinois and Massachusetts. In recent years, Massachusetts has seen steady growth in retail choice participation, while conditions in Ohio have caused participation to level off and in Illinois to decline.[183]

[182] S. Sergici, Status of Restructuring: Wholesale and Retail Markets, The Brattle Group, presented to the National Conference of State Legislatures, June 26, 2018.

[183] U.S. Energy Information Administration (EIA), Today in Energy: Electricity residential retail choice participation has declined since 2014 peak, November 8, 2018.

FIGURE 20: STATES WITH RETAIL ELECTRICITY CHOICE



Source/Notes: National Renewable Energy Laboratory (NREL), An Introduction to Retail Electricity Choice in the United States, August 2017, Figure 1.

The goals of restructuring for retail choice are to reduce average retail prices, enable greater access to renewable energy, integrate more flexible resources, and increase penetration of price-responsive demand.[184] Evidence from implementation of retail choice in other states has shown that in some places retail suppliers are innovating by bundling other services and products with electricity supply. Some innovations that have developed in retail markets are: (i) offering other eco-conscious products to green customers (100% renewable supply rates, energy audits, home protection, carbon offsets, demand response programs); (ii) non-traditional price structures (price risk management, flat monthly billing, free night usage, and various promotions and discounts); and (iii) bundled services (electricity plus gas service, home automation and security,

[184] See F. Graves, et al. Retail Choice: Ripe for Reform?, The Brattle Group, July 2018; T.L. Hogan, "Texas Electricity Prices Are Lower Due to Deregulation," American Institute for Economic Research (AIER), March 2, 2021; Grid Strategies, LLC, Who's the Buyer? Retail Electric Market Structure Reforms in Support of Resource Adequacy and Clean Energy Deployment, prepared for Wind Solar Alliance, March 2020; University of Texas Austin Energy Institute, The Timeline and Events of the February 2021 Texas Electric Grid Blackouts, July 2021, p. 89; P.R. Hartley, et al., Electricity reform and retail pricing in Texas, Journal of Energy Economics, Volume 80, 2019, pp. 1–11.

energy plus internet services).[185] The greatest and most widely-agreed-on benefits of retail choice are associated with larger customer classes, who tend to be sophisticated power consumers that typically exercise their right to switch providers at high rates, are able to optimize their own consumption, participate fully in wholesale markets (e.g., as DR resources), shop around for retailers or full-service energy service providers, and engage in green power purchase agreements.[186]

The benefits of retail competition have lagged and been less clear for mass-market (residential and small businesses) consumers, who tend to have lower switching rates in most states. In some cases, the explanation of lower switching rates is that retail electricity markets are too confusing, have high switching costs, or that alternative suppliers cannot offer sufficiently lower rates to make a change worthwhile.[187] In other cases, the retail markets are not sufficiently open to enable meaningful retail rate competition and impose excess barriers to entry to alternative suppliers (e.g., lack of real-time access to smart meter data, lack of ability for third party providers to take over billing functions).

Texas is unique in that it enables full retail choice for all customers who must either choose a competitive supplier or they will be assigned one.[188] While Texas does have a Provider of Last Resort (POLR), it is expensive relative to competitive retailers and generally encourages participation in the retail market. Texas regulators have taken a relatively “light touch” to regulating retail markets, allowing competitive retailers to set rates in ways that match their own costs and attract interest from customers. For these reasons, switching rates are higher in Texas than other states with retail choice, with some competitive retailers offering a variety of innovative rate offerings and deals to attract customers.

Texas retail market also is served under a competitive wholesale market model served by the Electric Reliability Council of Texas (ERCOT), which is a single-state RTO and is the only RTO in the U.S. that is not interconnected with its neighboring regions. Unlike the other U.S. RTO/EIM markets, Texas does not have a capacity market or capacity mechanism and is set up to produce

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185 F. Graves, et al. Retail Choice: Ripe for Reform?, The Brattle Group, July 2018.

186 A.J. Ros, An Econometric Assessment of Electricity Demand in the United States Using Utility-specific Panel Data and the Impact of Retail Competition on Prices, Energy Journal, 2017, Volume 38, pp. 73–99.

187 J. Kahn-Lang, Competing for (In)attention: Price Discrimination in Residential Electricity Markets, University of California Berkeley, Haas Energy Institute, November 28, 2022; M.J. Morey and L.D. Kirsch, Retail Choice in Electricity: What have we learned in 20 years?, Christensen Associates Energy Consulting LLC, prepared for Electric Markets Research Foundation, February 11, 2016;

188 This applies to the majority of the state that is within the ERCOT territory.

higher levels of energy price volatility, a key element of an "energy-only" market design. The implication of this higher wholesale market price volatility (combined with relatively few hedging controls or a traditional standard offer service in the retail market) is that high market price volatility can be passed directly to customers.

Typically, Texas competitive retail rates have been very low compared to national averages and customers have enjoyed low rates, but extreme events occasionally occur (most notably the extreme high prices that occurred during Winter Storm Uri).[189] Competitive retailers that were not sufficiently hedged against these events ended up passing the extreme wholesale prices onto customers. Households that experienced these price spikes were all on wholesale-indexed plans that tied their retail rates directly to wholesale prices. When wholesale gas and electricity prices spiked due to the natural gas scarcity and emergency conditions, the prices of these indexed plans followed suit. Later analysis has shown that these affected customers represented less than 1% of retail customers in ERCOT (since the majority of retail customers in Texas have fixed-rate retail plans) and many of these customers ultimately will not be liable for paying these bills due to subsequent consumer protection efforts.[190]

POTENTIAL ADVANTAGES

The potential advantages of pursuing partial or full retail choice include:

- Retail choice increases the transparency of costs and prices.

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[189] The ERCOT territory in Texas experienced more disruption from Winter Storm Uri than neighboring states in SPP and MISO since it is electrically isolated from its neighbors, which meant ERCOT operators were unable to draw power from other regions in the U.S. that were not experiencing extreme cold conditions at the same time. Furthermore, the areas of Texas that are outside of ERCOT territory fared considerably better during the storm, demonstrating the benefits of greater interconnection. The Energy Institute at The University of Texas Austin and FERC/NERC report the main causes of the severity of Winter Storm Uri were due to the lack of winterization of gas plants, which caused reduced gas production, and not due to the market structure. ERCOT ultimately had to shed 20,000 MW of firm load at the worst point of the event compared to SPP and MISO operators, which had to shed a combined total of 3,418 MW of firm load at their respective worst points, despite facing similar levels of plant outages due to the extreme cold conditions. See Federal Energy Regulatory Commission (FERC) and North American Reliability Corporation (NERC), FERC–NERC Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States, November, 16, 2021; University of Texas Austin Energy Institute, The Timeline and Events of the February 2021 Texas Electric Grid Blackouts, July 2021; and Texas Monthly, "El Paso Heeded the Warnings and Avoided a Winter Catastrophe," February 19, 2021.

[190] G. Sharfman and J. Merola, Beyond Texas Evaluating Customer Exposure to Energy Price Spikes: A Case Study of Winter Storm Uri, Interlometry, October 2021, pp. 24 and 25; Office of the Attorney General of Texas, Press Release "AG Paxton Ensures Forgiveness of $29 Million in Electric Bills for 24,000 Texans After Suing Griddy Energy, LLC," March 16, 2021.

- Retail markets are more efficient at passing through cost savings from wholesale markets to end consumers, which can lower average bills by incentivizing customers to manage their own consumption more efficiently.
- Retail competition is attractive for large C&I consumers, municipalities/coops, and communities to lower bills and accelerate energy policy goals.
- Opportunities are created for third-party DR/DER providers and aggregators to identify innovative products and services.
- State could be a more attractive location for future businesses, particularly large C&I customers that would take full advantage of available supply opportunities.

POTENTIAL DISADVANTAGES

The potential disadvantages of pursuing retail choice are mostly related to offering retail choice for small customers and include:

- Retail products can be confusing to small, less sophisticated buyers of electricity, potentially exposing them to higher market volatility and risk than under regulated rates.
- Difficult to fully facilitate competition in the residential and small business sector or extract benefits without also moving toward a competitive investment model in a coordinated fashion for the same customer classes.
- Additional regulation needed to protect residential consumers against excess price volatility, unfair or deceptive marketing practices, and ensure transparent communication of product offerings.
- Both partial and full retail access require mechanisms to equitably address legacy investment costs and avoid cost shifting.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

Legislation would likely be required to enable retail choice but can be implemented without any coordination from neighboring regions. Retail choice could be rolled out in a staged fashion, beginning with first offering partial retail choice to large customers where the benefits are greatest. Rates can then be unbundled across different components of the bill, increasing the transparency of costs relative to rates available on the wholesale market. Once sufficient experience is gained with partial retail choice, South Carolina can assess experience to date and determine whether full retail restructuring is desired.

Participation in an RTO will greatly increase the ability to effectively implement any level of retail choice; particularly one that offers a sufficient structure for ensuring resource adequacy and reliability on behalf of switching customers. As discussed above (under competitive investment reforms), the introduction of any level of retail choice should be done in coordination with generation planning and investment reforms so that legacy investment costs can be recovered in an equitable fashion. This may mean that a "transition charge" or "exit fee" would be assessed to relevant customer classes over a relevant transition period.

E. Community Choice Aggregation

DESCRIPTION AND RELEVANT CASE STUDIES

Community Choice Aggregation (CCA) programs enable local governments (cities and municipalities) to procure power on behalf of their residents, businesses, and municipal accounts from an alternative supplier while still receiving transmission and distribution service and consolidated billing from their existing utility provider. By forming a CCA, local governments assume control of procuring energy and capacity, while utilities maintain ownership over the transmission and distribution systems. By aggregating demand, participants in a CCA can gain leverage to negotiate better electricity rates with competitive suppliers and exert more control over the types of generation resources that that supplies their electricity.

While most CCAs emphasize reducing the cost of electricity, some also focus on: (i) supplying their customers demand through "green electricity" by procuring supply from renewable energy sources oftentimes through Power Purchase Agreements (PPAs); (ii) reducing greenhouse gas emissions; (iii) establishing new revenue streams to support local energy programs; and/or (iv) creating local jobs. Most CCAs seek to accomplish several of these goals simultaneously. Almost all CCAs offer equal or lower prices than the incumbent supplier with some offering savings as high as 15–20 percent.[191] In recent years, CCAs have also been able to take advantage of the decreasing costs of renewables to offer lower rates. Since most utilities procure renewable energy using long-term contracts and in some cases may have locked in their rates when renewables were more expensive, CCAs may sometimes be able to negotiate with newer, cheaper renewable energy providers.

[191] E. O'Shaughnessy, et al., Community Choice Aggregation: Challenges, Opportunities, and Impacts on Renewable Energy Markets, NREL, February 2019; Lean Energy, What is a CCA?, accessed January 11, 2023.

CCAs are currently authorized in 10 states including: Massachusetts (since 1997), Ohio (since 1999), Virginia (since 1999), California (since 2002), Rhode Island (since 2002), New Jersey (since 2003), Illinois (since 2009), New York (since 2014), New Hampshire (since 2019), and Maryland (since 2021).[192] The majority of these states (8 out of 10) follow the "opt-out" structure so that the CCA becomes the default electricity provider and customers must opt out in order to return to using an alternative competitive retail provider or standard offer service. The opt-out structure greatly increases program participation relative to a voluntary "opt in" structure, which requires consumers wanting to participate to complete an additional step. In 2020, approximately 4.7 million customers nationwide procured about 13 million MWh of voluntary green power through CCAs with the majority of these customers being in California (3.9 million customers).[193]

In cases where CCAs are enabled in regions with vertically integrated utility investment models, CCA legislation typically include provisions to prevent shifting legacy utility investment costs onto the customers that are not a part of the CCA and remain with the utility service. One common approach is to require CCAs to pay "exit-fees" to the existing utility to help cover a share of legacy investment costs, similar to those discussed above in the context of competitive retail supply.[194] In California this is implemented through the Power Charge Indifference Adjustment (PCIA), a charge that aims to ensure that both utility customers and those who have left the utility to join a CCA pay for the above market costs for electric generation resources that were procured by the utility on their behalf. "Above market" refers to the difference between what the utility pays for electric generation and current market prices for the sale of those resources. Along with the costs, the CCA receives its residual share of capacity credit and renewable energy credits over the transition period.

POTENTIAL ADVANTAGES

The potential advantages of community choice aggregation include:

- More control for communities to negotiate and lower their energy rates.
- Enables communities to more rapidly achieve green energy policy goals.

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192 United States Environmental Protection Agency (EPA), Community Choice Aggregation, Last Updated on November 21, 2022.

193 National Renewable Energy Laboratory (NREL), Status and Trends in the Voluntary Market (2020 data), September 29, 2021, slide 19.

194 Absent an exit fee or similar structure, the introduction of CCAs could risk inequitable cost shifting. By losing customers to the CCA, the incumbent utility must bear the costs of legacy investments, but now must do so over a smaller customer base. This dynamic drives a cross subsidy where the rates for the remaining utility customers rise as fewer customers must still cover past investments, while the CCA customers are able to reap the benefits of lower prices by procuring their supply from lower cost resources.

- Can spur local job creation, clean energy innovation, and investment for CCAs that opt to align these local goals with their power supply purchase agreements.

POTENTIAL DISADVANTAGES

The potential disadvantages of community choice aggregation include:

- Need to equitably address legacy investment costs and avoid cost shifting.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

Similar to the introduction of partial or full retail choice, the ability to effectively implement CCAs would be greatly enhanced by participation in a regional RTO or EIM market, particularly one with an effective mechanism for ensuring reliability and resource adequacy on behalf of CCAs and switching customers.

To enable Community Choice Aggregation, the South Carolina legislature would have to enact a law allowing for CCAs to form, designate which entities (counties, cities, towns, villages, etc.) could form a CCA, and would need to distinguish within that enabling legislation whether the opt-out or opt-in approach would be taken, among other provisions.[195] Additionally, the PSC would have to act to create a cost-recovery mechanism to be imposed on any CCA to prevent a shifting of costs onto the remaining customers of incumbent utilities.

F. Competitive Reforms to Enable Distributed Energy Resources

DESCRIPTION AND RELEVANT CASE STUDIES

The emergence of distributed energy technologies, electrified transport, smart homes, and behind-the-meter storage and generation will change the way customers interact with the distribution system. New consumer types, sometimes called "prosumers" not only draw power from the grid but can additionally provide generation to the grid, imparting a new bi-directional usage of the distribution system. Distributed Energy Resources (DERs) are small electricity resources that are distributed throughout the distribution system that may be uncontrollable or

[195] For a list of all CCA-enabling state legislation see Lean Energy, "CCA by State," accessed January 11, 2023.

controlled by DER aggregator companies.[196] The growing DER environment is distinct from the traditional approach of large power plants operated in a centralized fashion with unidirectional power flow. Examples of DERs can include resources such as Demand Response (DR) which can be customer or device curtailments; electric vehicles that can be controlled to charge at preferred times (or even discharge into the grid); heating ventilating and air conditioning (HVAC) building control devices; distributed behind-the-meter battery storage; or distributed rooftop solar. The number, variety, and quantity of DERs is rapidly increasing, as well as the available technologies and companies seeking to capture these resources' potential to offer valuable services to end use customers and the grid as a whole.

The distribution system consists of medium-voltage lines (usually on wooden poles) designed to carry several megawatts (up to tens of megawatts) of power from the high-voltage transmission grid to end users in homes and businesses. The transmission system, by contrast, uses tall (usually steel) pylons to move many hundreds or thousands of megawatts across an interstate grid. As generation technologies have become more modular, and as control and communications have dramatically decreased in cost, the opportunities to connect smaller DERs to consumer facilities (or directly to the utility distribution system) have expanded. At the same time, the distribution system, and the ability of DERs to support it, is of growing interest for several reasons:

- The growth of electric vehicles (and, in some states, electric heat) increases the strain on the distribution system;
- Net metering policies promote growing deployment of rooftop and small solar installations at customer facilities; and
- Greater reliance on electricity yields growing interest in microgrids and other technologies that can provide backup power and improve grid resilience.

DERs, when operated against the right incentive structure, offer a significant opportunity to efficiently and cost effectively meet customer preferences while lowering system costs. On the other hand, DERs facing an ineffective incentive structure (for example, one designed for inelastic customers) can introduce challenges to the system such as by increasing net load uncertainties.

[196] In the RTO environment, the participation of DER in wholesale markets (through an aggregator) has been mediated through FERC Order 2222, which sets minimum standards for reasonable access to wholesale markets by DER. Most of the high-level Order 2222 tariff rules for the RTOs have already been filed, and are planned for implementation later this decade or early in the next. These involve various software changes at the RTO level. The distribution utilities are making complementary plans to interface with the RTO to take a role in the dispatch of DER aggregations and to secure visibility into aggregate DER output and schedules. See Federal Energy Regulatory Commission, 172 FERC ¶ 61,247, Docket No. Rm18-9-000, Order No. 2222, issued September 17, 2020.

For example, distributed (solar) generation, storage, and EV resources that can be aggregated to be controllable will not be activated to operate the most beneficial way for the grid if there are no incentives to do so. The opportunities to better activate such resources include creating enhanced utility rates (as discussed above), joining RTO markets and enabling DERs to fully participate in providing RTO-defined system services such as capacity and ancillary services, opening retail markets sufficiently to enable DERs to operate with unique and innovative retail structures, and enabling DERs to offer their supply into all-source procurements. South Carolina has also taken through the Energy Freedom Act

Because they can provide benefits to consumers, to the utility's local distribution system, as well as to the bulk grid, the upfront costs of DERs can be more than offset by the combination of such benefits. For example, some customer-sited batteries in RTO territories reach a net profit by combining several stacked services such as capacity and frequency regulation sold to the RTO, while providing emergency backup service and customer bill management through peak shaving to the end user.[197] Similar concepts are being applied to solar projects, solar-battery hybrids, gas engines, controlled electric vehicle charging, thermostat aggregations, and other DERs.

Retailers, regulators, and utilities are rapidly exploring options for encouraging electric vehicle (EV) adoption and incentivizing efficient charging such as encouraging overnight EV charging.[198] Many rate designs are EV-specific TOU rates that are being offered as an option for home charging.[199] Utilities and competitive retailers also have experimented with a variety of ways to temporarily limit the impacts of existing rate designs on developers of high-speed public charging stations, to allow that industry to continue to develop as the EV market matures.[200] Methods to encourage electric heating adoption are also gaining traction. While some utilities and retailers have offered discounts for customers with electric heating for decades (through seasonal declining block rates or a reduced average rates) designs that minimize bills for customers with heat pumps while still remaining consistent with the overall rate design principle of cost-

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197 U.S Energy Information Agency (EIA), Battery Storage in the United States: An Update on Market Trends, August 2021.

198 R. Hledik, et al., Residential Electric Vehicle Time-Varying Rates That Work: Attributes That Increase Enrollment, prepared for the Smart Electric Power Alliance (SEPA), November 2019.

199 Direct Testimony of Sanem I. Sergici on behalf of New Hampshire Department of Energy, in the matter of: Public Service Company of New Hampshire D/B/A Eversource Energy, Electric Vehicle Make-ready and Demand Charge Alternative Proposals, Docket no. DE 21-078, February 25, 2022.

200 R. Hledik and J. Weiss, Increasing Electric Vehicle Fast Charging Deployment: Electricity Rate Design and Site Host Options, The Brattle Group, prepared for Edison Electric Institute, January 2019.

causation are increasingly being considered.[201] Load flexibility is being encouraged by retailers and utilities by offering increasingly sophisticated tariffs for large customers with flexible loads.[202] In some cases, these approaches are developed as a tailored offer for a single very large customer. Examples of such customers include data mining, pulp mills, electric vehicle fleets, and customers with large backup generators or behind-the-meter batteries.[203] In addition to rate designs, customers can be provided with tariff-based incentives to participate in demand response and load flexibility programs.[204] Payments to service provides for these programs often come in the form of rebates, bill credits, or rate discounts. Such programs are quickly evolving from conventional "peak clipping" programs to advanced load flexibility programs that provide a broader range of services to the grid (e.g., daily load shifting, ancillary services, geo-targeted demand reductions).[205]

DERs can be activated effectively through access to wholesale RTO markets (directly for large customers, or indirectly through retailers and aggregators for smaller customers). In RTOs, more services are available as market based products, which can be provided by any supplier (supply or demand side) that have the technical capabilities to do so. For example, market operators are exploring ways to enable electric vehicles to provide grid services, which has given rise to the Vehicle-to-Grid (V2G), or the more general Vehicle-to-Everything (V2X), concepts.[206] Access to these markets are often used to support DER business cases, in some cases making up half or more of the overall value of DER deployment.[207] Examples of such markets include ancillary services like frequency regulation and spinning reserves, the wholesale energy market featuring real-time prices, and capacity markets to signal the regional value of adding peak supply or

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[201] S. Sergici, et al., Heat Pump-Friendly Cost-Based Rate Designs, The Brattle Group, prepared for Energy Systems Integration Group (ESIG), January 2023.

[202] R. Hledik, et al., Distribution System Pricing with Distributed Energy Resources, prepared for Lawrence Berkeley National Laboratory (LBNL), May 2016.

[203] A. Faruqui and R. Hledik, An Assessment of Nova Scotia Power's Proposed Extra Large Industrial Active Demand Control Tariff, September 26, 2019

[204] The Brattle Group, A National Roadmap for Grid-Interactive Efficient Buildings, prepared with Lawrence Berkeley National Laboratory for the United States Department of Energy, May 17, 2021.

[205] R. Hledik, et al., The National Potential for Load Flexibility: Value and Market Potential Through 2030, The Brattle Group, June 2019.

[206] A.W. Thompson and Y. Perez, Vehicle-to-Everything (V2X) energy services, value streams, and regulatory policy implications, Energy Policy, Volume 137, February 4, 2020.

[207] See Hledik, et al., Stacked Benefits: Comprehensively Valuing Battery Storage in California, The Brattle Group, Prepared for Eos Energy Storage, September 2017; Fitzgerald, et al., The Economics Of Battery Energy Storage: How Multi-Use, Customer-Sited Batteries Deliver The Most Services And Value To Customers And The Grid, Rocky Mountain Institute, September 2015; Value Stacking in Minster: A Rural Village Leverages Solar, Storage and 4 Revenue Streams, Smart Electric Power Alliance, November 2016.

removing peak demand. Other grid resiliency products such as black-start capabilities and emergency back-up generation exist and new services are also developing to benefit distribution systems, such as distribution build-out deferral, local capacity, reactive power support, and voltage regulation, though markets for these services are in the nascent stages of development and are typically settled by out-of-market mechanisms.[208]

POTENTIAL ADVANTAGES OF REFORMS TO ENABLE DERS

Potential disadvantages of reforms to enable DERs include:

- Deployment of DER is more targeted to use cases and geographic areas where the benefits to the total electric system (including customer-side, distribution, and transmission) exceed the costs, enhancing efficiency for all users.
- Customer preferences are enhanced without imposing costs on other customers.
- Electric services (like electric transport and heat) can be expanded with reduced increases in distribution system cost and enhance resiliency from on-site generation.

POTENTIAL DISADVANTAGES OF REFORMS TO ENABLE DER

Potential disadvantages of reforms to enable DERs include:

- Implementation challenges and care to ensure a wide variety of DERs are fully enabled to provide their potential services.
- Some types of DER programs require investment costs for controls and dispatchability (though if developed by third-party aggregators, the associated costs can be borne by the private companies rather than customers).

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

The opportunities to better activate cost-effective DERs include through enhanced utility rates (as discussed above), joining RTO markets and enabling DERs to fully participate in providing RTO-defined system services such as capacity and ancillary services, opening retail markets sufficiently to enable DERs to operate against unique and innovative retail structures, and enabling DERs to offer their services into all-source procurements. Pursuing one or more of these avenues may require third-party DER providers and aggregators to be explicitly enabled in both law and regulation within the respective reform areas.

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[208] A.W. Thompson and Y. Perez, Vehicle-to-Everything (V2X) energy services, value streams, and regulatory policy implications, Energy Policy, Volume 137, February 4, 2020.

G. Third-Party Energy Efficiency Administrator

DESCRIPTION AND RELEVANT CASE STUDIES

Energy Efficiency (EE) programs are designed to reduce the energy used by electric appliances such as heaters, air conditioning, other home appliances, manufacturing, electronics, etc. EE programs can include rebates for home weatherization, heating electrification, and more efficient lighting, air conditioning, or refrigerators. EE programs can save costs for customers, increase grid reliability, and result in health benefits.[209] Energy efficiency programs can be especially beneficial for low to moderate-income households. Such households tend to have disproportionately high energy bill burdens and are more likely to live in older housing with less insulation and (in some regions) more expensive heating fuel.[210] Energy efficiency improvements can therefore result in significantly lower bills for some of these customers.[211]

In most regions, energy efficiency programs are run and administered by utilities. However, utility cost recovery mechanisms (such as recovery of fixed costs through rates that are based on purchase volumes) can provide a disincentive to the utility for any reduction in sales. While such tensions are generally workable, and can yield successful EE programs, utilities, regulators, and other stakeholders sometimes view them as a problem that warrants alternative solutions.[212]

One solution would mandate the creation of a third-party entity (typically a state agency or non-profit) to deliver energy efficiency services. Third-party entities are typically established by the state and are funded by a ratepayer surcharge. The third-party EE provider acts as a separate organization that designs and administers EE programs, funding allocations, and reviews measurement and verification of program effectiveness.[213] The programs and the third-party EE administrator may also be subject to state commission oversight.

Jurisdictions that have third-party energy efficiency administrators in the U.S. include New York, Vermont, and Wisconsin.[214] In New York, the New York State Energy Research and Development

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[209] International Energy Agency, Capturing the Multiple Benefits of Energy Efficiency, 2014.

[210] American Council for Energy-Efficient Economy (ACEEE), "Low-Income Energy Efficiency Programs," January 19, 2023.

[211] Environmental Protection Agency (EPA), Efficiency Vermont Case Study, accessed January 18, 2023.

[212] California Public Utilities Commission (CPUC), Energy Efficiency Policy Manual. April 2020.

[213] Environmental Protection Agency (EPA), "Local Utilities and Other Energy Efficiency Program Sponsors," accessed January 25, 2023.

[214] We note there are also third-party EE administrators in Canada in Ontario and New Brunswick.

Authority (NYSERDA) runs energy efficiency focused programs such as “Pay for Performance.”[215] Pay for Performance allows third parties that bundle efficiency to bid for energy saving contracts. Vermont has Efficiency Vermont, an energy efficiency utility which is a non-profit organization overseen by the Vermont Public Utility Commission. Efficiency Vermont is funded by a surcharge on customer bills and offers a wide variety of energy efficiency programs, including educational programs, rebates for ventilation equipment, and efficient light bulb programs.[216] Wisconsin has “Focus on Energy,” a statewide energy efficiency program funded by ratepayers through utilities.[217] Utilities recover the costs of funding the program through a rate surcharge. Focus on Energy delivered >$1 billion in economic benefits between 2010–2017 with $4.36 in benefits for every $1 invested in energy efficiency in 2017.[218]

POTENTIAL ADVANTAGES

Potential advantages of introducing a third-party energy efficiency administrator include:

- Singular focus on EE could mean more scope for innovative and effective EE programs.
- Overcomes potential misaligned incentives with utility administration.
- May activate a larger number and variety of EE providers.
- Possible efficiencies with one entity for the whole state and reduced work for utilities.

POTENTIAL DISADVANTAGES

Potential disadvantages of introducing a third-party energy efficiency administrator include:

- Implementation costs and time.
- May not be necessary in situations where utility programs are already achieving high success, eliminating effective utility programs would lose established infrastructure, experience, and customer relations that already exist within the utility.
- Requires sufficiently long funding commitment for institution-building.

[215] NYSERDA and National Grid, Pay-for-Performance Initiative, September 2019.

[216] U.S. Department of Energy (DOE), “Energy Efficiency Policies and Programs,” accessed January 19, 2023.

[217] Midwest Energy Efficiency Alliance, “Midwest Energy Efficiency Alliance,” accessed January 20, 2023.

[218] Midwest Energy Efficiency Alliance, Energy Efficiency, accessed January 20, 2023.

IMPLEMENTATION CONSIDERATIONS FOR SOUTH CAROLINA

In South Carolina, Energy Efficiency programs are currently administered by utilities. Costs for energy efficiency programs are passed through to ratepayers or amortized over time to retain a share of savings. To establish a third-party energy administrator, legislation would have to be passed. The scope of the third-party EE administrator could be expansive for the entire state and cover all EE programs, or could be subject to PSC oversight such that some programs could be offered on a statewide basis while others are targeted in some utility areas if minimum EE targets are not already achieved through existing utility programs. The PSC would regulate compensation for the independent administrator through a surcharge on all bills in South Carolina.

H. Recommendations for Retail Market Reforms

Based on these analyses of retail reforms summarized above, we recommend that South Carolina consider the following options:

- **Pursue a path toward greater regional coordination via an EIM or RTO wholesale market**, as to support enabling additional retail rate choices to retail customers. Entering an RTO will immediately increase competitive forces by empowering cooperative and municipal utilities in South Carolina to consider a greater variety of self-supply and contractual options for securing their energy supply.
- **Authorize (and perhaps require) the PSC and regulated utilities to evaluate options for expanded and enhanced retail rate choices** to South Carolina customers, such as increasingly advanced time-varying rates seeking to activate new DR/DER technologies, green tariffs and related green energy options, and other rate designs to enhance efficiency.
- **Introduce partial retail choice for large C&I customers**, enabling businesses that are large, sophisticated energy consumers to negotiate rates, self-supply with clean energy, participate in RTO markets as demand-side resources, and optimize their own consumption.
- **Introduce a path for Community Choice Aggregation**, enabling local communities to pursue environmental goals and negotiate rates.
- **Defer consideration of retail choice for residential and small business customers** until after other reforms are implemented. Revisit the option to expand retail choice to all consumers after gaining experience with wholesale market participation, partial retail choice, and the other market reforms discussed above.
- **Enable distributed energy resources and demand response** from third-party providers to compete in all-source supply solicitation, both within competitive IRP-based all-source procurement processes and within RTO markets.
- **Authorize the PSC to appoint a third-party EE administrator** to support energy efficiency program development 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.

List of Acronyms

ACEEE	American Council for Energy-Efficient Economy
ASCS	All-Source Competitive Solicitation
BA	NERC Balancing Authority
BAA	NERC Balancing Authority Area
C&I	Commercial & Industrial
CAISO	California Independent System Operator
CEC	California Energy Commission
CCA	Community Choice Aggregation
COPUC	Colorado Public Utilities Commission
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CP	Coincident Peak
CSU	Colorado Springs Utilities
CTCA	Carolinas Transmission Coordination Agreement
DA	Day Ahead
DCA	Department of Consumer Affairs
DER	Distributed Energy Resource
DOE	Department of Energy
DR	Demand Response
DSO	Distribution System Operator
ECAR	East Central Area Reliability Council
EDAM	Extended Day-Ahead Market
EE	Energy Efficiency
EIM	Energy Imbalance Market
EIPC	Eastern Interconnection Planning Collaborative
EIS	Energy Information System
EPA	Environmental Protection Agency
EPE	El Paso Electric
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission

FRCC	Florida Reliability Coordinating Council
FRR	Fixed Resource Requirement
G&T	Generation and Transmission
IESO	Independent Electricity System Operator (of Ontario)
IOU	Investor Owned Utility
ISO	Independent System Operator
IPP	Independent Power Producer
IRM	Installed Reserve Margin
IRP	Integrated Resource Plan
JDA	Joint Dispatch Agreement
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
LMP	Locational Marginal Price
LTSG	Long Term Study Group
MAIN	Mid-American Interpool Network
MAPP	Midcontinent Area Power Pool
MISO	Midcontinent Independent System Operator
MPSC	Michigan Public Service Commission
NCP	Non-Coincident Peak
NEM	Net Energy Metering
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NERP	North Carolina Energy Regulatory Process
NESCOE	New England States Committee on Electricity
NIPSCO	Northern Indiana Public Service Company
NREL	National Renewable Energy Laboratory
NRRI	National Regulatory Research Institute
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations & Maintenance
ORS	Office of Regulatory Staff
PJM	PJM Interconnection
PMPA	Piedmont Municipal Power Association
PNM	Public Service Company of New Mexico
POLR	Provider of Last Resort
PPA	Power Purchase Agreement
PRPA	Platte River Power Authority
PSCO	Public Service Company of Colorado

PSO	Power System Optimizer
PSC	Public Service Commission
PTR	Peak Time Rebates
PUC	Public Utilities Commission
PURPA	Public Utilities Regulatory Policies Act of 1978
QF	Qualifying Facility
RA	Resource Adequacy
RC	NERC Reliability Coordinator
RFP	Request for Proposal
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
Santee Cooper	South Carolina Public Service Authority
SEC	Securities Exchange Commission
SEEM	Southeast Energy Exchange Market
SERC	Southeastern Electric Reliability Council
SOCO	Southern Company
SPE	Special Purpose Entity
SPP	Southwest Power Pool
TOP	NERC Transmission Operator
TOU	Time-of-Use
TVA	Tennessee Valley Authority
VACAR	The group of four companies consisting of Duke Energy Carolinas, Duke Energy Progress, South Carolina Public Service Authority, and Dominion South Carolina
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WRAP	Western Resource Adequacy Program

Appendix A: Load Diversity Analysis

South Carolina + PJM	Duke Energy Progress Combined	Duke Energy Carolinas	PJM	Santee Cooper	Dominion Energy	Regional Total	South Carolina Total	South Carolina Savings %
South Carolina Share of Load	10%	29%	0%	100%	100%			
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	
A. Original 1-NCP Peak								
2011	13,315	19,644	158,043	5,676	4,885	201,563	17,507	
2012	13,193	19,473	154,339	5,387	4,761	197,153	17,033	
2013	12,523	18,239	157,509	5,029	4,574	197,874	16,068	
2014	14,215	20,799	141,678	5,673	4,853	187,218	17,892	
2015	15,569	21,101	143,633	5,869	4,970	191,142	18,426	
2016	13,298	20,671	152,177	4,794	4,807	195,747	16,840	
2017	14,534	20,120	145,637	4,989	4,701	189,981	16,894	
2018	15,519	21,620	150,670	5,203	4,756	197,768	17,690	
2019	13,669	20,597	151,570	4,558	4,714	195,108	16,526	
2020	13,233	20,398	144,588	4,467	4,586	187,272	16,207	
2021	13,046	20,310	148,770	4,634	4,573	191,333	16,317	
Average	**13,829**	**20,270**	**149,874**	**5,116**	**4,744**	**193,833**	**17,036**	
B. PJM-South Carolina 1-CP Peak								
2011	13,154	19,305	158,043	5,129	4,720	200,351	16,682	
2012	12,574	18,382	154,339	4,733	3,988	194,016	15,232	
2013	11,954	17,829	157,509	4,638	4,025	195,955	14,954	
2014	14,215	20,246	137,998	5,673	4,853	182,985	17,734	
2015	12,491	19,884	143,065	4,941	4,646	185,027	16,520	
2016	13,079	20,236	150,826	4,541	4,618	193,300	16,251	
2017	12,640	19,878	145,325	4,298	4,200	186,341	15,444	
2018	12,405	19,597	150,670	4,081	4,116	190,869	15,039	
2019	12,563	20,359	151,570	4,290	4,372	193,154	15,738	
2020	13,207	20,087	144,588	4,074	4,175	186,131	15,311	
2021	13,046	20,147	148,216	4,379	4,520	190,308	15,963	
Average	**12,848**	**19,632**	**149,286**	**4,616**	**4,385**	**190,767**	**15,897**	
C. Savings (A - B)								
2011	161	339	0	547	165	1,212	825	4.7%
2012	619	1,091	0	654	773	3,137	1,801	10.6%
2013	569	410	0	391	549	1,919	1,114	6.9%
2014	0	553	3,680	0	0	4,233	158	0.9%
2015	3,078	1,217	569	928	324	6,116	1,906	10.3%
2016	219	435	1,351	253	189	2,447	588	3.5%
2017	1,894	242	312	691	501	3,640	1,449	8.6%
2018	3,114	2,023	0	1,122	640	6,899	2,650	15.0%
2019	1,106	238	0	268	342	1,954	788	4.8%
2020	26	311	0	393	411	1,141	896	5.5%
2021	0	163	555	255	53	1,026	355	2.2%
Average	**981**	**638**	**588**	**500**	**359**	**3,066**	**1,139**	**6.6%**

Notes/Sources: FERC Form 714.

SERTO	PowerSouth Energy Cooperative	Associated Electric Cooperative, Inc.	Duke Energy Progress Combined	Duke Energy Carolinas	Louisville Gas and Electric Company and Kentucky Utilities Company	South Carolina Public Service Authority	Dominion Energy South Carolina, Inc.	Southern Company Services, Inc.	Tennessee Valley Authority	Regional Total	South Carolina Total	South Carolina Savings %
SC Share of Load	0%	0%	10%	29%	0%	100%	100%	0%	0%			
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)			
A. Original 1-CP Peak												
2011	2,081	4,376	13,263	19,515	7,046	5,415	4,855	41,149	30,815	128,514	17,174	
2012	1,872	4,301	13,072	19,276	7,153	5,304	4,689	41,074	30,796	127,536	16,809	
2013	1,742	3,953	12,406	18,120	6,691	4,928	4,467	38,149	28,131	118,586	15,814	
2014	2,361	4,639	14,098	20,088	7,272	5,500	4,638	43,538	32,793	134,927	17,289	
2015	2,117	4,412	14,160	20,364	6,936	5,439	4,810	43,311	31,602	133,152	17,485	
2016	1,887	4,281	13,160	20,345	6,685	4,749	4,749	42,343	29,552	127,751	16,630	
2017	1,976	4,400	13,409	19,946	6,582	4,735	4,662	41,587	29,658	126,953	16,438	
2018	2,340	5,070	15,112	20,821	6,831	5,072	4,710	42,694	31,400	134,049	17,243	
2019	1,938	4,845	13,065	20,440	6,744	4,496	4,679	42,806	29,404	128,417	16,325	
2020	1,978	4,486	13,149	20,161	6,495	4,420	4,569	41,363	28,783	125,404	16,067	
2021	2,087	5,736	12,901	20,295	6,659	4,520	4,554	44,558	30,268	131,577	16,165	
Average	2,035	4,591	13,436	19,943	6,827	4,961	4,671	42,052	30,291	128,806	16,676	
B. SERTO 1-CP Peak												
2011	1,839	4,005	13,072	18,856	6,550	5,318	4,749	40,600	30,075	125,062	16,762	
2012	1,791	3,998	12,707	18,832	7,057	5,068	4,529	40,970	30,677	125,627	16,249	
2013	1,602	3,568	11,813	17,690	6,637	4,601	4,172	37,433	27,856	115,369	15,010	
2014	2,288	4,111	14,079	20,088	6,863	5,435	4,530	43,285	32,109	132,786	17,114	
2015	2,057	4,018	14,090	20,283	6,810	5,411	4,772	42,336	31,023	130,798	17,389	
2016	1,686	3,445	12,844	20,101	6,489	4,602	4,623	41,836	29,043	124,669	16,256	
2017	1,698	4,139	12,466	19,739	6,534	4,250	4,235	40,916	29,249	123,225	15,374	
2018	2,250	4,403	14,545	20,490	6,658	4,968	4,633	41,876	30,618	130,441	16,911	
2019	1,793	3,905	12,373	19,792	6,246	4,220	4,421	42,310	29,246	124,304	15,535	
2020	1,822	3,759	12,986	20,030	6,180	4,253	4,344	40,728	28,260	122,362	15,621	
2021	1,897	4,521	12,290	20,044	6,295	4,244	4,365	44,451	30,039	128,144	15,567	
Average	1,884	3,988	13,024	19,631	6,574	4,761	4,488	41,522	29,836	125,708	16,163	
C. Savings (MW) (A - B)												
2011	242	371	191	659	496	98	106	548	740	3,451	411	2.4%
2012	82	303	365	444	96	236	161	104	119	1,910	560	3.3%
2013	141	385	593	430	54	327	295	717	276	3,217	803	5.1%
2014	74	529	19	0	410	65	108	253	684	2,140	175	1.0%
2015	61	394	71	82	126	28	38	976	579	2,354	96	0.5%
2016	201	836	316	245	197	147	126	506	509	3,082	374	2.3%
2017	278	261	943	206	49	485	427	672	409	3,728	1,064	6.5%
2018	90	667	567	331	173	104	78	818	782	3,608	332	1.9%
2019	146	940	692	649	499	277	258	496	158	4,113	789	4.8%
2020	157	727	163	132	315	166	226	635	523	3,043	446	2.8%
2021	190	1,215	611	252	364	276	189	108	230	3,434	598	3.7%
Average	**151**	**603**	**412**	**312**	**252**	**201**	**183**	**530**	**455**	**3,098**	**514**	**3.1%**

Notes/Sources: FERC Form 714.

Appendix B: Investment Savings from Partial or Full Reliance on Competitive Supply

High Case			2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Scenario: Status Quo with IRP																				
SC Non-Coincident Peak Load	MW	[1]	17,130	17,105	17,210	17,329	17,445	17,595	17,642	17,748	17,929	18,100	18,251	18,382	18,624	18,777	18,931	19,086	19,243	19,400
SC Reserve Requirement	MW	[2]	20,042	20,013	20,136	20,274	20,410	20,586	20,641	20,765	20,977	21,177	21,354	21,507	21,790	21,969	22,149	22,331	22,514	22,698
Existing Capacity (minus Retirements)	MW	[3]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Incremental Capacity	MW	[4]	167	0	414	553	1,522	1,698	1,997	2,806	3,017	3,827	4,004	4,157	4,441	4,619	4,799	4,981	5,164	5,348
IRP Planned Capacity	MW	[5]	20,842	20,813	20,936	21,074	21,210	21,386	21,441	21,565	21,777	21,977	22,154	22,307	22,590	22,769	22,949	23,131	23,314	23,498
Incremental Capacity Cost	($/MW-Day)	[6]	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320
Net Cost of Incremental Capacity	($ Mln)	[7]	$19	$0	$48	$65	$178	$198	$233	$328	$352	$447	$468	$486	$519	$540	$561	$582	$603	$625
Scenario: Incremental Participation																				
SC Coincident Peak Load	MW	[8]	15,994	15,970	16,068	16,179	16,288	16,428	16,471	16,571	16,739	16,899	17,040	17,162	17,389	17,531	17,675	17,820	17,966	18,113
RTO Reserve Requirement	MW	[9]	18,345	18,318	18,430	18,557	18,682	18,843	18,893	19,007	19,200	19,383	19,545	19,685	19,945	20,109	20,273	20,440	20,607	20,776
Existing Capacity (minus Retirements)	MW	[10]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Incremental Capacity	MW	[11]	0	0	0	0	0	0	249	1,047	1,240	2,034	2,196	2,335	2,595	2,759	2,923	3,090	3,257	3,426
IRP Planned Capacity	MW	[12]	20,675	20,572	20,522	20,522	19,688	19,688	19,693	19,807	20,000	20,183	20,345	20,485	20,745	20,909	21,073	21,240	21,407	21,576
Net Purchase (Sale) from Market	MW	[13]	(2,331)	(2,254)	(2,091)	(1,964)	(1,007)	(845)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)
Incremental Capacity Cost	($/MW-Day)	[14]	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320	$320
PJM Market Price	($/MW-Day)	[15]	$50	$34	$55	$75	$95	$116	$136	$157	$177	$197	$218	$238	$259	$259	$259	$259	$259	$259
Total Cost of Incremental Capacity	($ Mln)	[16]	$0	$0	$0	$0	$0	$0	$29	$122	$145	$238	$256	$273	$303	$322	$341	$361	$380	$400
Revenue from Capacity Sales	($ Mln)	[17]	$43	$28	$42	$54	$35	$36	$40	$46	$52	$58	$64	$70	$75	$75	$75	$75	$75	$75
Net Cost of Incremental Supply	($ Mln)	[18]	(43)	(28)	(42)	(54)	(35)	(36)	(11)	77	93	180	193	203	228	247	266	285	305	325
Savings Relative to Status Quo	**($ Mln)**	**[19]**	**$62**	**$28**	**$90**	**$118**	**$213**	**$234**	**$244**	**$251**	**$259**	**$267**	**$275**	**$282**	**$291**	**$293**	**$295**	**$296**	**$298**	**$300**
Scenario: Full Participation																				
SC Coincident Peak Load	MW	[20]	15,994	15,970	16,068	16,179	16,288	16,428	16,471	16,571	16,739	16,899	17,040	17,162	17,389	17,531	17,675	17,820	17,966	18,113
RTO Reserve Requirement	MW	[21]	18,345	18,318	18,430	18,557	18,682	18,843	18,893	19,007	19,200	19,383	19,545	19,685	19,945	20,109	20,273	20,440	20,607	20,776
Existing Capacity (minus Retirements)	MW	[22]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Net Purchase (Sale) from Market	MW	[23]	(2,331)	(2,254)	(2,091)	(1,964)	(1,007)	(845)	(551)	247	440	1,234	1,396	1,535	1,795	1,959	2,123	2,290	2,457	2,626
PJM Market Price	($/MW-Day)	[24]	$50	$34	$55	$75	$95	$116	$136	$157	$177	$197	$218	$238	$259	$259	$259	$259	$259	$259
Net Cost of Incremental Supply	($ Mln)	[25]	(43)	(28)	(42)	(54)	(35)	(36)	(27)	14	28	89	111	133	169	185	200	216	232	248
Savings Relative to Status Quo	**($ Mln)**	**[26]**	**$62**	**$28**	**$90**	**$118**	**$213**	**$234**	**$261**	**$314**	**$324**	**$358**	**$357**	**$352**	**$349**	**$355**	**$360**	**$366**	**$371**	**$377**

Sources and Notes:
All values expressed in nominal U.S. dollars.

[1]: 2023-2035: Peak load from utility IRPs. 2036-onward: Previous year increased by long-term load weighted average load growth derived from utility IRPs.
[2]: [1] x (1 + 17%); based on SC utility target reserve margins from IRPs.
[3], [10], [22]: Initial capacity plus initial demand side management in 2023 minus cumulative retirements from utility IRPs.
[4], [11]: Cumulative future builds, designated uprates and incremental Demand Side Management from IRPs.
[5]: [3] + [4].
[6], [14]: Reference and Low Case: Inflation adjusted PJM 2023/2024 BRA Gross CONE in 2022$. High Case: Inflation adjusted PJM 2023/2024 BRA Gross CONE in 2022$ + 4%. Assumes that the incremental cost of capacity is flat in nominal terms.
[7]: [4] x [6] x 365.
[8], [20]: South Carolina coincident peak load after joining with PJM calculated from 2011-2021 historical gross load data from FERC Form 714.
[9], [21]: [8] x (1 + 14.7%), reserve margin is PJM RTO target reserve margin from 2024/2025 BRA.
[12]: [10] + [11].
[13]: [9] - [12].
[15], [24] :

Reference and High Case: 2023-2024: PJM Historical BRA clearing results. 2025-2035: Linear interpolation until reaching market equilibirum, assumed to be the long-term PJM Net Cost of New Entry (Net CONE) from 2024/25 BRA. 2036 onward: PJM Net CONE from 2024/25 BRA.

Low Case: 2023-2024: PJM Historical BRA clearing results. 2025-2035: Linear interpolation until reaching market equilibirum, assumed to be equal to the incremental capacity cost. 2036 onward: incremental capacity cost.

[16]: [11] x [14]x 365.
[17]: -[13] x [15] x 365.
[18]: [16] - [17].
[19]: [7] - [18].
[23]: [21] - [22].
[25]: [23] x [24] x 365.
[26]: [7] - [25].

Reference Case			2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Scenario: Status Quo with IRP																				
SC Non-Coincident Peak Load	MW	[1]	17,130	17,105	17,210	17,329	17,445	17,595	17,642	17,748	17,929	18,100	18,251	18,382	18,624	18,777	18,931	19,086	19,243	19,400
SC Reserve Requirement	MW	[2]	20,042	20,013	20,136	20,274	20,410	20,586	20,641	20,765	20,977	21,177	21,354	21,507	21,790	21,969	22,149	22,331	22,514	22,698
Existing Capacity (minus Retirements)	MW	[3]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Incremental Capacity	MW	[4]	0	0	269	253	1,222	1,398	1,697	2,506	2,717	3,527	3,704	3,857	4,141	4,319	4,499	4,681	4,864	5,048
IRP Planned Capacity	MW	[5]	20,675	20,572	20,791	20,774	20,910	21,086	21,141	21,265	21,477	21,677	21,854	22,007	22,290	22,469	22,649	22,831	23,014	23,198
Incremental Capacity Cost	($/MW-Day)	[6]	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308
Net Cost of Incremental Capacity	($ Mln)	[7]	$0	$0	$30	$28	$137	$157	$191	$282	$305	$397	$416	$434	$465	$486	$506	$526	$547	$568
Scenario: Incremental Participation																				
SC Coincident Peak Load	MW	[8]	15,994	15,970	16,068	16,179	16,288	16,428	16,471	16,571	16,739	16,899	17,040	17,162	17,389	17,531	17,675	17,820	17,966	18,113
RTO Reserve Requirement	MW	[9]	18,345	18,318	18,430	18,557	18,682	18,843	18,893	19,007	19,200	19,383	19,545	19,685	19,945	20,109	20,273	20,440	20,607	20,776
Existing Capacity (minus Retirements)	MW	[10]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Incremental Capacity	MW	[11]	0	0	0	0	0	0	0	747	940	1,734	1,896	2,035	2,295	2,459	2,623	2,790	2,957	3,126
IRP Planned Capacity	MW	[12]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	19,507	19,700	19,883	20,045	20,185	20,445	20,609	20,773	20,940	21,107	21,276
Net Purchase (Sale) from Market	MW	[13]	(2,331)	(2,254)	(2,091)	(1,964)	(1,007)	(845)	(551)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)	(500)
Incremental Capacity Cost	($/MW-Day)	[14]	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308
PJM Market Price	($/MW-Day)	[15]	$50	$34	$55	$75	$95	$116	$136	$157	$177	$197	$218	$238	$259	$259	$259	$259	$259	$259
Total Cost of Incremental Capacity	($ Mln)	[16]	$0	$0	$0	$0	$0	$0	$0	$84	$106	$195	$213	$229	$258	$276	$295	$314	$332	$351
Revenue from Capacity Sales	($ Mln)	[17]	$43	$28	$42	$54	$35	$36	$27	$29	$32	$36	$40	$43	$47	$47	$47	$47	$47	$47
Net Cost of Incremental Supply	($ Mln)	[18]	(43)	(28)	(42)	(54)	(35)	(36)	(27)	55	73	159	173	185	211	229	248	266	285	304
Savings Relative to Status Quo	**($ Mln)**	**[19]**	**$43**	**$28**	**$72**	**$82**	**$172**	**$193**	**$218**	**$226**	**$232**	**$238**	**$243**	**$248**	**$255**	**$256**	**$258**	**$260**	**$262**	**$263**
Scenario: Full Participation																				
SC Coincident Peak Load	MW	[20]	15,994	15,970	16,068	16,179	16,288	16,428	16,471	16,571	16,739	16,899	17,040	17,162	17,389	17,531	17,675	17,820	17,966	18,113
RTO Reserve Requirement	MW	[21]	18,345	18,318	18,430	18,557	18,682	18,843	18,893	19,007	19,200	19,383	19,545	19,685	19,945	20,109	20,273	20,440	20,607	20,776
Existing Capacity (minus Retirements)	MW	[22]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Net Purchase (Sale) from Market	MW	[23]	(2,331)	(2,254)	(2,091)	(1,964)	(1,007)	(845)	(551)	247	440	1,234	1,396	1,535	1,795	1,959	2,123	2,290	2,457	2,626
PJM Market Price	($/MW-Day)	[24]	$50	$34	$55	$75	$95	$116	$136	$157	$177	$197	$218	$238	$259	$259	$259	$259	$259	$259
Net Cost of Incremental Supply	($ Mln)	[25]	(43)	(28)	(42)	(54)	(35)	(36)	(27)	14	28	89	111	133	169	185	200	216	232	248
Savings Relative to Status Quo	**($ Mln)**	**[26]**	**$43**	**$28**	**$72**	**$82**	**$172**	**$193**	**$218**	**$268**	**$277**	**$308**	**$306**	**$300**	**$296**	**$301**	**$305**	**$310**	**$315**	**$320**

Sources and Notes:
All values expressed in nominal U.S. dollars.
[1]: 2023-2035: Peak load from utility IRPs. 2036-onward: Previous year increased by long-term load weighted average load growth derived from utility IRPs.
[2]: [1] x (1 + 17%); based on SC utility target reserve margins from IRPs.
[3], [10], [22]: Initial capacity plus initial demand side management in 2023 minus cumulative retirements from utility IRPs.
[4], [11]: Cumulative future builds, designated uprates and incremental Demand Side Management from IRPs.
[5]: [3] + [4].
[6], [14]: Reference and Low Case: Inflation adjusted PJM 2023/2024 BRA Gross CONE in 2022$. High Case: Inflation adjusted PJM 2023/2024 BRA Gross CONE in 2022$ + 4%. Assumes that the incremental cost of capacity is flat in nominal terms.
[7]: [4] x [6] x 365.
[8], [20]: South Carolina coincident peak load after joining with PJM calculated from 2011-2021 historical gross load data from FERC Form 714.
[9], [21]: [8] x (1 + 14.7%), reserve margin is PJM RTO target reserve margin from 2024/2025 BRA.
[12]: [10] + [11].
[13]: [9] - [12].
[15], [24] :

Reference and High Case: 2023-2024: PJM Historical BRA clearing results. 2025-2035: Linear interpolation until reaching market equilibirum, assumed to be the long-term PJM Net Cost of New Entry (Net CONE) from 2024/25 BRA. 2036 onward: PJM Net CONE from 2024/25 BRA.

Low Case: 2023-2024: PJM Historical BRA clearing results. 2025-2035: Linear interpolation until reaching market equilibirum, assumed to be equal to the incremental capacity cost. 2036 onward: incremental capacity cost.

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[18]: [16] - [17].
[19]: [7] - [18].
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[25]: [23] x [24] x 365.
[26]: [7] - [25].

Low Case			2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Scenario: Status Quo with IRP																				
SC Non-Coincident Peak Load	MW	[1]	17,130	17,105	17,210	17,329	17,445	17,595	17,642	17,748	17,929	18,100	18,251	18,382	18,624	18,777	18,931	19,086	19,243	19,400
SC Reserve Requirement	MW	[2]	20,042	20,013	20,136	20,274	20,410	20,586	20,641	20,765	20,977	21,177	21,354	21,507	21,790	21,969	22,149	22,331	22,514	22,698
Existing Capacity (minus Retirements)	MW	[3]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Incremental Capacity	MW	[4]	0	0	269	124	1,022	1,198	1,497	2,306	2,517	3,327	3,504	3,657	3,941	4,119	4,299	4,481	4,664	4,848
IRP Planned Capacity	MW	[5]	20,675	20,572	20,791	20,645	20,710	20,886	20,941	21,065	21,277	21,477	21,654	21,807	22,090	22,269	22,449	22,631	22,814	22,998
Incremental Capacity Cost	($/MW-Day)	[6]	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308
Net Cost of Incremental Capacity	($ Mln)	[7]	$0	$0	$30	$14	$115	$135	$168	$259	$283	$374	$394	$411	$443	$463	$483	$504	$524	$545
Scenario: Incremental Participation																				
SC Coincident Peak Load	MW	[8]	15,994	15,970	16,068	16,179	16,288	16,428	16,471	16,571	16,739	16,899	17,040	17,162	17,389	17,531	17,675	17,820	17,966	18,113
RTO Reserve Requirement	MW	[9]	18,345	18,318	18,430	18,557	18,682	18,843	18,893	19,007	19,200	19,383	19,545	19,685	19,945	20,109	20,273	20,440	20,607	20,776
Existing Capacity (minus Retirements)	MW	[10]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Incremental Capacity	MW	[11]	0	0	0	0	0	0	0	547	740	1,534	1,696	1,835	2,095	2,259	2,423	2,590	2,757	2,926
IRP Planned Capacity	MW	[12]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	19,307	19,500	19,683	19,845	19,985	20,245	20,409	20,573	20,740	20,907	21,076
Net Purchase (Sale) from Market	MW	[13]	(2,331)	(2,254)	(2,091)	(1,964)	(1,007)	(845)	(551)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)
Incremental Capacity Cost	($/MW-Day)	[14]	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308	$308
PJM Market Price	($/MW-Day)	[15]	$50	$34	$59	$84	$109	$134	$159	$184	$208	$233	$258	$283	$308	$308	$308	$308	$308	$308
Total Cost of Incremental Capacity	($ Mln)	[16]	$0	$0	$0	$0	$0	$0	$0	$61	$83	$172	$191	$206	$236	$254	$272	$291	$310	$329
Revenue from Capacity Sales	($ Mln)	[17]	$43	$28	$45	$60	$40	$41	$32	$20	$23	$26	$28	$31	$34	$34	$34	$34	$34	$34
Net Cost of Incremental Supply	($ Mln)	[18]	(43)	(28)	(45)	(60)	(40)	(41)	(32)	41	60	147	162	175	202	220	239	257	276	295
Savings Relative to Status Quo	**($ Mln)**	**[19]**	**$43**	**$28**	**$75**	**$74**	**$155**	**$176**	**$200**	**$218**	**$223**	**$227**	**$232**	**$236**	**$241**	**$243**	**$245**	**$246**	**$248**	**$250**
Scenario: Full Participation																				
SC Coincident Peak Load	MW	[20]	15,994	15,970	16,068	16,179	16,288	16,428	16,471	16,571	16,739	16,899	17,040	17,162	17,389	17,531	17,675	17,820	17,966	18,113
RTO Reserve Requirement	MW	[21]	18,345	18,318	18,430	18,557	18,682	18,843	18,893	19,007	19,200	19,383	19,545	19,685	19,945	20,109	20,273	20,440	20,607	20,776
Existing Capacity (minus Retirements)	MW	[22]	20,675	20,572	20,522	20,522	19,688	19,688	19,444	18,760	18,760	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150	18,150
Net Purchase (Sale) from Market	MW	[23]	(2,331)	(2,254)	(2,091)	(1,964)	(1,007)	(845)	(551)	247	440	1,234	1,396	1,535	1,795	1,959	2,123	2,290	2,457	2,626
PJM Market Price	($/MW-Day)	[24]	$50	$34	$59	$84	$109	$134	$159	$184	$208	$233	$258	$283	$308	$308	$308	$308	$308	$308
Net Cost of Incremental Supply	($ Mln)	[25]	(43)	(28)	(45)	(60)	(40)	(41)	(32)	17	33	105	132	159	202	220	239	257	276	295
Savings Relative to Status Quo	**($ Mln)**	**[26]**	**$43**	**$28**	**$75**	**$74**	**$155**	**$176**	**$200**	**$243**	**$249**	**$269**	**$262**	**$252**	**$241**	**$243**	**$245**	**$246**	**$248**	**$250**

Sources and Notes:

All values expressed in nominal U.S. dollars.

[1]: 2023-2035: Peak load from utility IRPs. 2036-onward: Previous year increased by long-term load weighted average load growth derived from utility IRPs.

[2]: [1] x (1 + 17%); based on SC utility target reserve margins from IRPs.

[3], [10], [22]: Initial capacity plus initial demand side management in 2023 minus cumulative retirements from utility IRPs.

[4], [11]: Cumulative future builds, designated uprates and incremental Demand Side Management from IRPs.

[5]: [3] + [4].

[6], [14]: Reference and Low Case: Inflation adjusted PJM 2023/2024 BRA Gross CONE in 2022$. High Case: Inflation adjusted PJM 2023/2024 BRA Gross CONE in 2022$ + 4%. Assumes that the incremental cost of capacity is flat in nominal terms.

[7]: [4] x [6] x 365.

[8], [20]: South Carolina coincident peak load after joining with PJM calculated from 2011-2021 historical gross load data from FERC Form 714.

[9], [21]: [8] x (1 + 14.7%), reserve margin is PJM RTO target reserve margin from 2024/2025 BRA.

[12]: [10] + [11].

[13]: [9] - [12].

[15], [24] :

Reference and High Case: 2023-2024: PJM Historical BRA clearing results. 2025-2035: Linear interpolation until reaching market equilibirum, assumed to be the long-term PJM Net Cost of New Entry (Net CONE) from 2024/25 BRA. 2036 onward: PJM Net CONE from 2024/25 BRA.

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[16]: [11] x [14]x 365.

[17]: -[13] x [15] x 365.

[18]: [16] - [17].

[19]: [7] - [18].

[23]: [21] - [22].

[25]: [23] x [24] x 365.

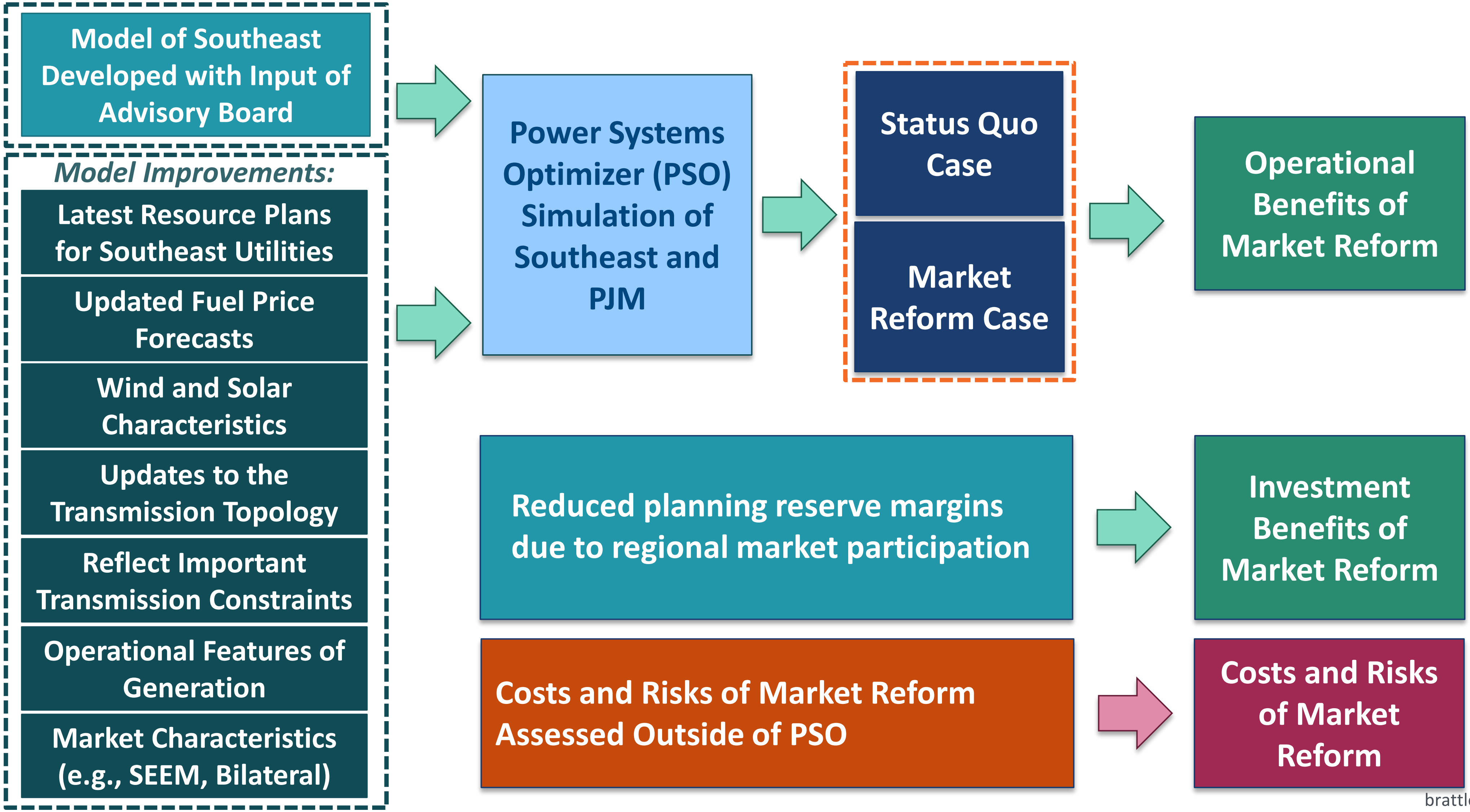
[26]: [7] - [25].

APPENDIX C:
Operational Simulation of Regional Wholesale Market Options for South Carolina

The Brattle Group
April 2023

Contents

Study Framework and Benefits Calculation



Simulated Market Reform Options

We simulated four different market reform scenarios representing part of the spectrum of possible market reform options.

Market Reform Options

- **Joint Dispatch Agreement in the Carolinas**
- **Energy Imbalance Market in the Southeast**
- **Southeast RTO (w/ Vertically Integrated Utility)**
- **Carolinas in PJM RTO (w/ Vertically Integrated Utility**

The analysis started with an assessment of the Status Quo, including the SEEM

- We modeled the entire Southeast, incorporating Advisory Board members' data
- The SEEM footprint reflected all announced membership as of February 1, 2023
- The EIM and Southeast RTO footprints cover the existing SEEM footprint

Simulated one 2030 scenario for each reform option and compared it against the Status Quo

- 2030 was chosen as a single proxy year to represent average savings over the next two decades

Overview of Modeling Approach

Simulations of the Carolinas within the broader Southeast + PJM region to assess operational benefits of market reforms

Utilized Power System Optimizer (PSO), an advanced market simulation model

- Nodal mixed-integer model representing each load and generator bus in the Southeast
- Licensed through Enelytix
- Detailed operating reserve and ancillary service product definition
- Detailed representation of the transmission system (both physical power flows and contract paths)
- Used a pre-populated model of the Southeast region provided by Enelytix
- Updated modeling assumptions to reflect the most recent utility resource plans and forecasts of system conditions and costs
- Hourly granularity due to limited data availability, but model can be enhanced for sub-hourly analysis

ENELYTIX® powered by PSO

PSO is uniquely suited to simulate bilateral trading, joint dispatch, imbalance markets, and RTOs because it can simulate multiple stages of system operator decision making

ENELYTIX®
powered by PSO

Power System Optimizer (PSO), developed by Polaris Systems Optimization, Inc. is a state-of-the-art market and production cost modeling tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual RTO and ISO market operations. Such nodal market modeling is a commonly used method for assessing the operational benefits of wholesale market reforms (e.g., JDAs, EIMs, RTOs).

PSO can be used to test system operations under varying assumptions, including but not limited to: generation and transmission additions or retirements, de-pancaked transmission and scheduling charges, changes in fuel costs, novel environmental and clean energy regulations, alternative reliability criteria, and jointly-optimized generating unit commitment and dispatch. PSO can report hourly or sub-hourly energy prices at every bus, generation output for each unit, flows over all transmission facilities, and regional ancillary service prices, among other results. Comparing these results among multiple modeled scenarios reveals the impacts of the study assumptions on the relevant operational metrics (e.g. power production, emissions, fuel consumption, or production costs). Results can be aggregated on a unit, state, utility, or regional level.

PSO has important advantages over traditional production cost models, which are designed primarily to model dispatchable thermal generation and to focus on wholesale energy markets only. The model can capture the effects of increasing system variability due to large penetrations of non-dispatchable, intermittent renewable resources on thermal unit commitment, dispatch, and deployment of operating reserves. PSO simultaneously optimizes energy and multiple ancillary services markets on an hourly or sub-hourly timeframe.

Like other production cost models, PSO is designed to mimic ISO operations: it commits and dispatches individual generating units to meet load and other system requirements, subject to various operational and transmission constraints. The model is a mixed-integer program minimizing system-wide operating costs given a set of assumptions on system conditions (e.g., load, fuel prices, transmission availability, etc.). Unlike some production cost models, PSO simulates trading between balancing areas based on contract-path transmission rights to create a more realistic and accurate representation of actual trading opportunities and transactions costs. This feature is especially important for modeling non-RTO regions like the Southeast.

One of PSO's distinguishing features is its ability to evaluate system operations at different decision points, represented as "cycles," which occur at different times ahead of the operating hour and with different amounts of information about system conditions available. Under this sequential decision-making structure, PSO can simulate initial cycles to optimize unit commitment, calculate losses, and solve for day-ahead unit dispatch targets. Subsequent cycles can refine unit commitment decisions for fast-start resources and re-optimize unit dispatch based on the parameters of real-time energy imbalance markets. The market structure can be built into sequential cycles in the model to represent actual system operation for utilities that conduct utility-specific unit commitment in the day-ahead period but participate in real-time energy imbalance markets that allow for re-optimization of dispatch and some limited re-optimization of unit commitment. For example, PSO can simulate an initial cycle that determines day-ahead unit commitment decisions that reflects the constraints faced by, and decisions made by, individual utilities when committing their resources in the day-ahead timeframe. The initial day-ahead commitment cycle is followed by cycles that simulate day-ahead economic dispatch, including bilateral trading of power, and a real-time economic dispatch, reflecting trades in real time (whether bilateral or optimized through an EIM or RTO). Explicit commitment and dispatch cycle modeling allows more accurate representation of individual utility preference to commit local resources for reliability, but share the provision of energy around a given commitment.

Simulating Several Wholesale Market Cycles

PSO simulates sequential decision cycles representing operational decisions at different points in time and with varying information about system conditions. Subsequent cycles realize uncertain outcomes, such as forced generation outages

- Market structures (e.g. bilateral, SEEM, EIM, RTO) are differentiated in our model via the following assumptions:
  - Wheeling fees and hurdle rates between utilities
  - Transmission availability for market transactions
  - Pooled (or not pooled) unit commitment and dispatch decisions
  - Reserve requirements

Day-Ahead Cycle	SEEM Cycle	Real-Time Cycle
Unit Commitment and Bilateral Trading	**SEEM Trading**	**Real-Time Dispatch**
– In non-RTO cases, resources committed and dispatched on utility-specific basis; DA bilateral trades occur – In RTO, unit commitment and dispatch optimized across footprint	– Bilateral SEEM trades take place subject to available transmission on defined contract paths between BAs	– Dispatch adjustments on utility-specific basis in non-RTO cases – In RTO, EIM, and JDA, dispatch optimization subject to physical transmission constraints

Simulating Several Wholesale Market Cycles (cont'd)

The model setup for the South Carolina wholesale market simulation effort contains four cycles to simulate unit commitment and dispatch decisions in three different timeframes and within different market structures. The four cycles (three time frames) simulated in this model are:

- **Day-Ahead Unit Commitment Cycle:** the model optimizes unit commitment decisions, 24 hours at a time (with 48-hour look ahead), for long-lead time resources such as coal and nuclear plants, based on their relative economics and operating characteristics (e.g., minimum run time, maintenance schedules, etc.), transmission constraints, and trading frictions. The model ensures that enough resources are committed to serve forecasted load, accounting for average transmission losses and the need for ancillary services. Separate regions' commitment decisions are segregated through higher hurdle rates on imports and exports. Trading within a single balancing area, like the various PJM sub-zones, is not subject to any hurdles.
- **Day-Ahead Economic Dispatch Cycle:** the model solves for the optimal level of hourly day-ahead dispatch and trading in 24-hour forward-looking optimization cycles, with 48-hour look ahead periods. Dispatch across the study footprint is optimized based on resource economics. In this cycle, the model also co-optimizes ancillary service procurement for each area. The high hurdle rates for unit commitment are lowered to enable more bilateral trading between balancing areas.
- **SEEM Cycle:** the model simulates SEEM market activity through one-hour optimization horizons. Utilities are assumed to offer unused transmission, represented as the difference between their day-ahead trading volume and the total contract path limits, into the market. We limit SEEM trading volumes based on input about expected participation from the Carolina utilities. No fast-start unit commitment is allowed in the SEEM market due to the non-firm nature of the transactions. Changes to generation availability, such as forced outages, which were not "visible" during the day-ahead cycle become visible during this cycle.
- **Real-Time Cycle:** this cycle simulated the operation of the real-time imbalance markets, such as through EIM and RTO transactions. In this cycle, the model can re-optimize dispatch levels and unit commitment decisions for fast-start thermal resources (based on the assumption that the real-time market design allows for unit re-commitment).

These cycles will take on different assumptions, depending on market structure. In a bilateral (Status Quo) setting, all are set up to analyze utility-specific unit commitment and dispatch decisions, with each of them including hurdle rates and transmission fees that limit the amount of economic transactions that can take place between the utilities. In the RTO and EIM scenarios, all of the cycles are set up to simulate market-wide optimization of unit commitment and dispatch. In the RTO setting, there would be no hurdle rates between market participants in any of the cycles, allowing the model to optimize both unit commitment and dispatch in the market footprint on both a day-ahead and real-time basis. In the EIM Case, the day-ahead cycles continue to operate like the bilateral case, while the real-time cycle operates like the RTO cases.

Operational Benefit Metrics: Adjusted Production Cost

Adjusted Production Cost (APC) is a standard metric used to capture the direct variable energy-related costs from a customer impact perspective

The APC is the sum of production costs and purchased power less off-system sales revenue:

(+) Production costs (fuel, startup, variable O&M, emissions costs) for generation owned or contracted by the load-serving entities

(+) Cost of bilateral and market purchases valued at the BAA's load-weighted energy price

(−) Revenues from bilateral and market sales valued at the BAA's generation-weighted energy price

The APC is calculated for the Status Quo Case (including SEEM) and for each of the four market reform cases to determine the reduction in APC due to market reform

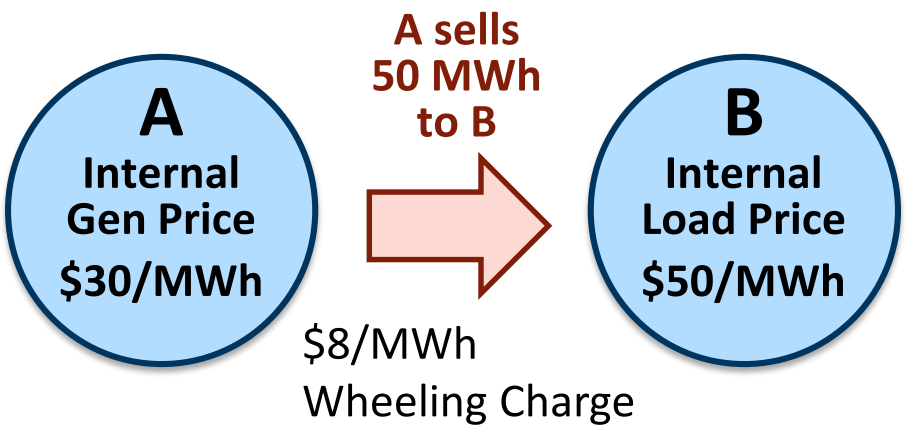
- By using the generation price of the exporter and load price of the importer for sales revenues and purchase costs, the APC metric does not capture wheeling revenues and the remaining portion of the value of the trade to the counterparties (see next slide)

Operational Benefit Metrics: Wheeling Revenues, Trading Gains

Based on the simulation results, we also estimate several additional impacts from increased trading facilitated by the market reforms.

- **Wheeling Revenues:** collected by the exporting BAAs based on OATT rates
- **Trading Gains:** buyer and seller split 50/50 the trading margin (and congestion revenues in EIM/RTO)

EXAMPLE:



The <u>APC metric</u> only uses internal prices for purchase cost and sales revenues, which does not capture part of the value:

- A receives $30×50MWh=$1,500 in APC sales revenues
- B pays $50×50MWh=$2,500 in APC purchase costs

➔ $1,000 of trading value not captured in APC metric

Trading value = $20/MWh Δprice x 50 MWh = $1000

- Exporter A receives wheeling revenues: $8/MWh x 50MWh = $400
- Remaining $600 trading gain split 50/50: both A and B receive $300

Modeling Steps

Step 1 – Benchmarked and Calibrated the Model
- Simulated the Southeast using 2020 inputs to verify system dynamics
- Ensured that SEEM member entities and PJM were correctly represented
- Adjusted model based on stakeholder input

Step 2 – Created 2030 Status Quo Case
- Modeled SEEM market
- Sought input from the Advisory Board
- Updated inputs to forecasted 2030 values

Step 3 – Simulated Market Reform Options
- Modeled four individual market reform options
- Compared benefit metrics against status quo case

Simulated Market Reform Benefits Are Conservative

The following factors ensure that modeled benefits associated with market reform are conservative:

- **Forecast uncertainty.** The simulations do not account for day-ahead forecast error of renewable generation and load. We apply the same hourly load and renewable generation in the day-ahead unit commitment and dispatch optimization, as in the real-time cycle. Therefore, our simulations of the real-time balancing cycle do not capture the benefit regional wholesale markets provide by optimizing dispatch to manage more challenging real-time conditions due to forecasting uncertainty.
- **Hourly modeling.** The modeling simulates hourly granularity of real-time market conditions (without uncertainty). This will understate the additional intra-hour, real-time benefits of a JDA, EIM, and RTO and result in understated estimates of EIM and RTO benefits relative to the Status Quo.
- **Natural gas price volatility.** The model uses natural gas fuel price forecasts provided by the Advisory Board utility members. Forecasts apply average daily price volatility and average geographic differences in prices, which does not capture periods of extreme volatility and large regional fluctuations in gas prices, such as those experienced during severe winter weather. Modeling natural gas price volatility in line with these events would increase the operational benefits of all regional market options studied by creating larger gains from trading power across the regional footprint.
- **Normalized weather conditions.** We do not model heat waves, cold snaps, or other weather events and uniquely challenging market conditions. Historical experience has shown that such events significantly increase production costs and regional trading values. Improved market integration would help to cope with such events at a lower cost, resulting in increased benefits that are not captured in our simulations.
- **Transmission outages.** The model does not include transmission outages, which understates the efficiency gains achieved in a regional market. The optimization performed in a wholesale market can lower the cost of re-dispatching the system during transmission outages by drawing on resources from across the footprint.

Simulated Market Reform Benefits Are Conservative (cont'd)

- **2030 transmission upgrades.** 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 EIM or a regional market would increase.
- **Status Quo market efficiency.** The simulations assume each Balancing Area fully optimizes its resources based on a security-constrained optimal unit commitment and dispatch. In addition, simulated SEEM transactions in our 2030 Status Quo Case are almost five 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). Our 2030 representation of the Status Quo, including SEEM, thus appears to be significantly more efficient than the actual market. This means that the incremental benefits from the other market reform options studied (the JDA, EIM, and two RTO options) would be greater than estimated.

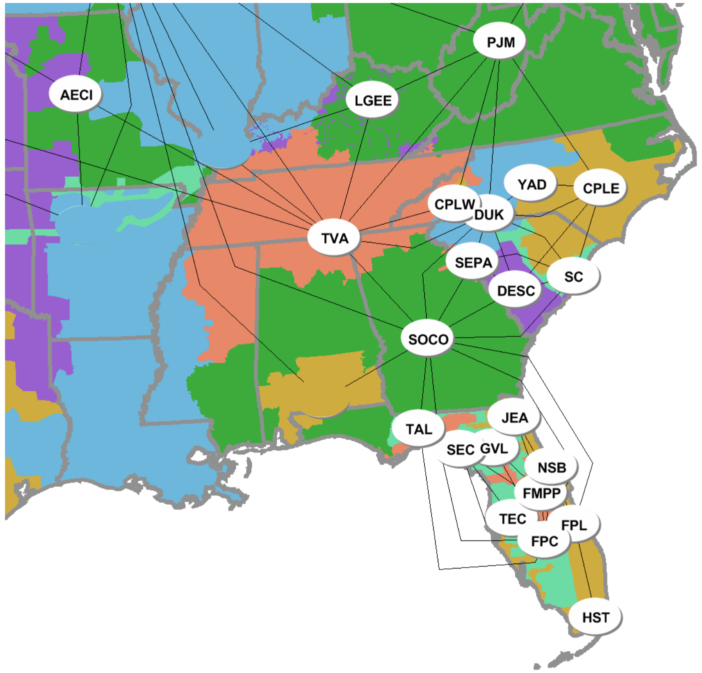
Modeling Assumptions

Model Footprint

We modeled a large portion of the Eastern Interconnect, including South Carolina and the rest of VACAR, SERC, FRCC, and PJM, to represent the SEEM market and relevant neighboring trading partners

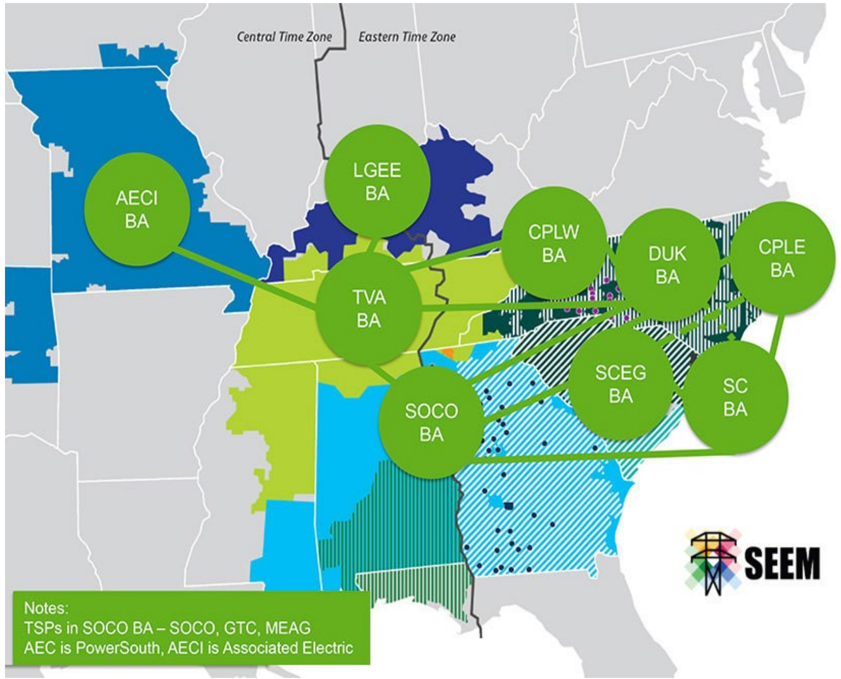
- We included all current SEEM members, including the Florida utilities currently in the process of joining
- We aggregated balancing footprints and trading barriers for each modeled case
- Trading with external areas (e.g. NYISO, MISO, and SPP) is modeled as fixed interchanges matching 2020 hourly transactions

Model Footprint



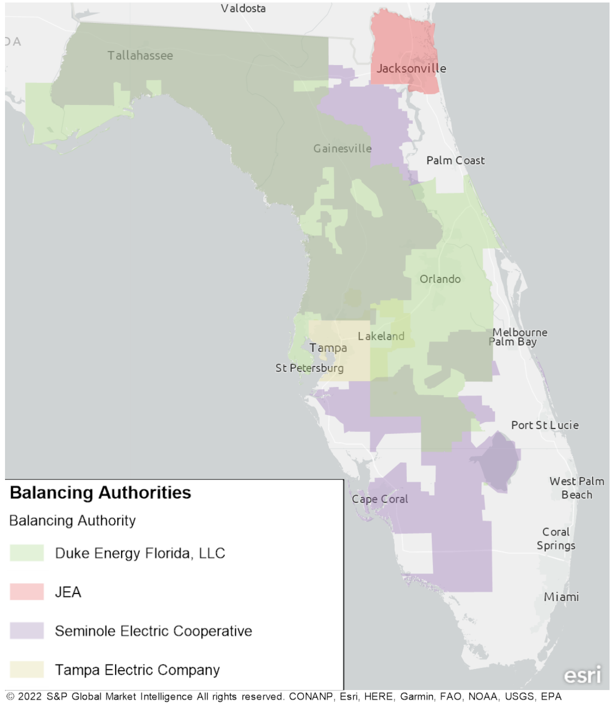
Source: NERC, "NERC Balancing Authority Areas", October, 2019.

Initial SEEM Footprint



Source: Southeast Energy Exchange Market.

Additional Florida SEEM Participants



Source: S&P Global.

Demand Assumptions

We relied on Advisory Board member utility input, FERC-714 data, and utility IRPs for peak and total demand assumptions

- PJM demand forecasts are based on PJM's 2021 zonal load forecasts (source)
- South Carolina utilities are modeled as the planning areas reported in FERC-714, including municipal and co-op utilities' loads in the projections for Duke and Santee Cooper. Duke is represented as a single balancing authority area, reflecting plans to unify Duke Energy Carolinas and Duke Energy Progress subject to regulatory approval

Load shapes are based on historical hourly demand profiles from the FERC-714 filings, with scaling to 2030 peak and total energy values

2030 Demand Assumptions

Utility	Total Load (GWh)	Peak Load (GW)
Duke Energy Progress and Duke Energy Carolinas (in both North and South Carolina)	171,490	35.8
Santee Cooper	28,697	5.6
Dominion South Carolina	25,078	4.8
PJM (without South Carolina, without Duke in North Carolina)	820,584	158.8
Southeast for purposes of modeling SEEM, EIM, and Southeastern RTO cases (without South Carolina, without Duke in North Carolina)	559,710	100.6

Capacity Mix

2030 capacity mixes are based on integrated resource plans, Advisory Board member utility data for the Carolinas, and other public sources, such as the EIA and trade press

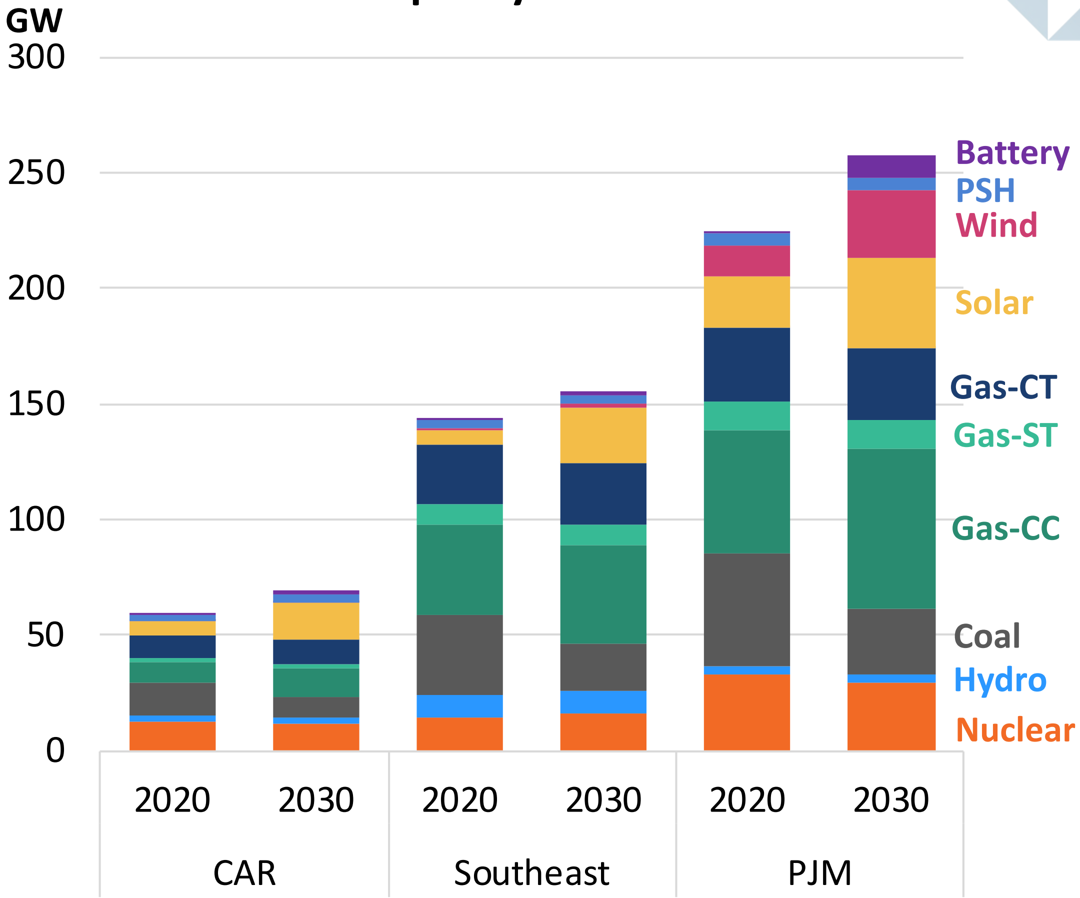
2030 capacity mixes reflect increasing renewables deployment and coal retirements

- PJM resource mix assumes member-states meet 2030 RPS targets
- Renewables output profiles are based on data from NREL (day-ahead forecasting uncertainty was not implemented)
- Seasonal hydro output variation reflects an average year, based on input from stakeholders

There is uncertainty about the Winyah coal plant's replacement

- Based on conversations with Santee Cooper and Central Electric Co-Op, we assume that these two entities will procure replacement capacity separately
- We model the Winyah replacement as two combined cycle gas plants with capacities equal to Santee Cooper's and Central Electric' ownership stakes in Winyah

Modeled Capacity Mix 2020 vs. 2030



Notes: Carolinas includes all of Duke, Dominion SC, and Santee Cooper. Southeast includes all non-Carolinas SEEM members. "PJM" represents the current footprint, not including the Carolinas.

2030 Capacity Updates

The evolution of the Southeast and PJM resource mix is marked by coal being replaced with renewables and storage

- Tables indicate changes from 2022-2030

Modeled Capacity Changes By Area

Area	Retirements			Additions		
	Coal	Gas	Nuclear	Solar	Wind	Storage
	MW	*MW*	*MW*	*MW*	*MW*	*MW*
Duke	3,498	-	793	6,223	600	2,052
DESC	684	-	-	398	-	122
SC	1,150	-	-	1,474	-	-
SOCO	6,673	-	-	5,201	-	1,051
TVA	4,814	-	-	5,129	-	-
Rest of SERC	1,013	208	-	1,298	-	240
FRCC	1,059	-	-	16,157	-	3,516
PJM	12,821	-	1,268	13,366	15,210	9,171

Carolinas Thermal Capacity Changes

Plant	Area	Type	Capacity (MW)
Retirements			
Winyah	SC	Coal	1,150
Wateree Units 2 & 3	DESC	Coal	684
Marshall Units 1 & 2	DESC	Coal	760
Mayo Unit 1	Duke	Coal	713
Roxboro Units 1 & 2	Duke	Coal	1,053
James Rogers Unit 5	Duke	Coal	546
G.G. Allen Units 1 & 5	Duke	Coal	426
H. B. Robinson Unit 2	Duke	Nuclear	793
Additions			
TBD	SC	CC	1,119
TBD	Duke	CC	2,906
TBD	Duke	CT	1,105

Note: Santee Cooper new CC capacity represents the replacement for Winyah plant, and is modeled as two separate units owned by Santee Cooper and Central Electric Cooperative.

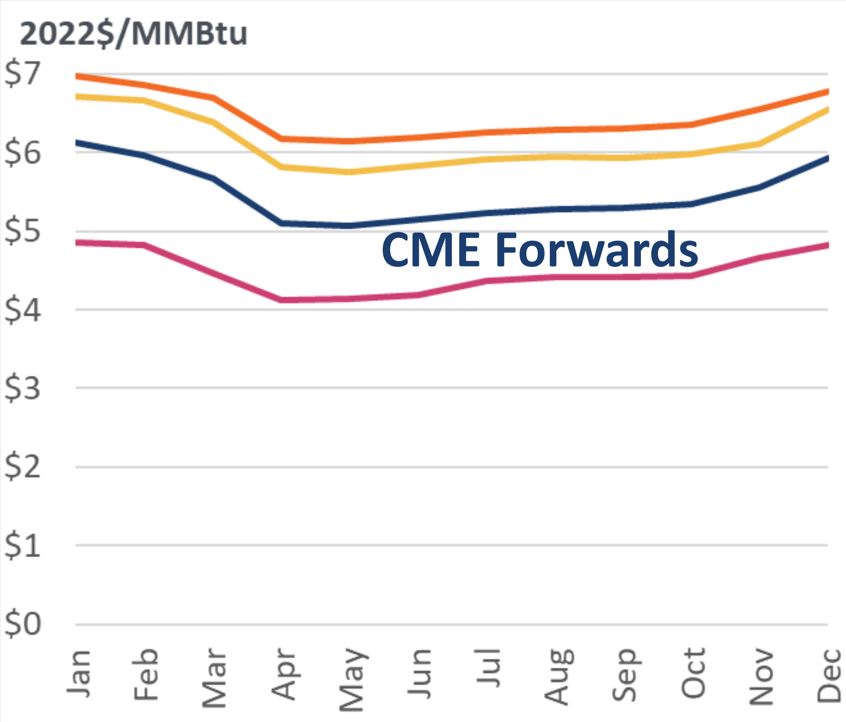
Natural Gas Prices

We used Henry Hub options quotes for 2030 from the Chicago Mercantile Exchange Group in the model

- These projections are in the middle of forecasts provided by advisory board member utilities (yellow, orange, and pink lines)
- Variation in Henry Hub price projections arises from recent gas market volatility due to the war in Ukraine and the European energy crisis

We also model unit-specific delivery adders based on data provided by advisory board member utilities and daily gas price volatility based on 2020 actual gas prices sourced from S&P Global

2030 Henry Hub Price Projections



Source: CME Group Henry Hub Natural Gas Option Quotes as of Oct 28, 2022

2030 Capacity Weighted Average Gas Price

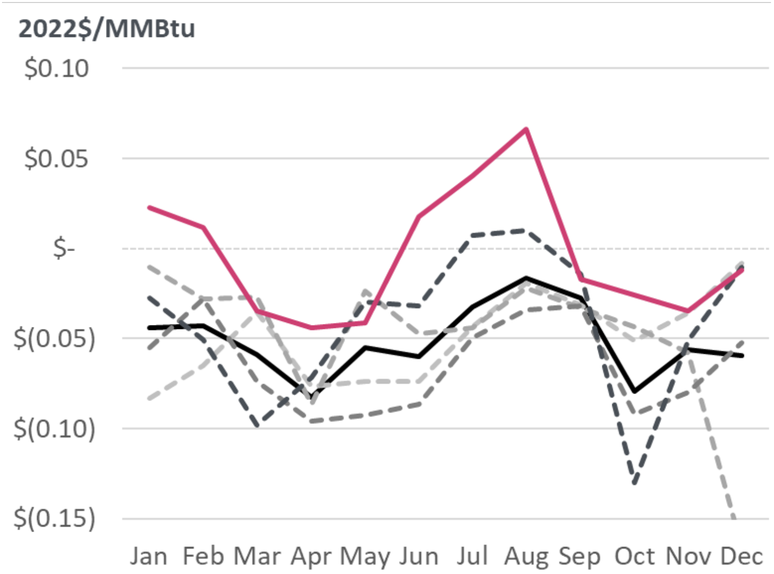
Area	$/MMBtu
Duke	$4.19
Dominion SC	$4.42
Santee Cooper	$4.06
Southern Company	$4.05
Tennessee Valley Authority	$3.99
Associated Electric Coop.	$4.07
Lousiville Gas & Electric	$3.55
Power South Cooperative	$4.60
FL-SEEM Members	$4.30
Rest of Florida	$4.23
PJM	$3.78

Natural Gas Prices (continued)

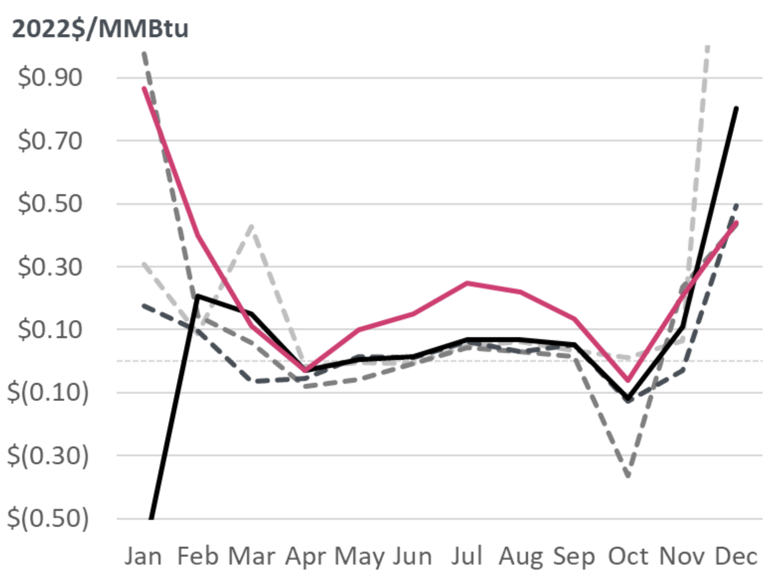
We assumed basis differentials with Henry Hub based on Advisory Board member utility input

- If multiple stakeholder basis differential forecasts were available for a given gas price hub, we chose the forecast most similar to historical basis differentials, assuming that the recent gas price volatility would subside by 2030
- If only one stakeholder forecast was available, we adjusted it to match the average 2017-2020 basis differential
- The charts below compare historical basis differentials (grayscale) to the chosen stakeholder-provided data (pink)

Transco Z4 Basis Differentials



Transco Z5 Basis Differentials



Note: Historical basis differentials sourced from S&P Global.

Legend: 2017 | 2018 | 2019 | 2020 | Historical Average | Stakeholder Data

Other Fuel Prices

Fuel oil prices are based on historical spot prices as of March 18, 2021, projected to 2030 using EIA AEO 2021 trends

Uranium prices are based on stakeholder-provided data

Plant-level coal prices are based on S&P Global power plant operations database, with 2030 projections using EIA AEO trajectories

- Annual price of coal delivered ($/ton) divided by average heat content (Btu/lbs)
- 2020 benchmarking runs apply a downward coal price adjustment for Duke, Santee Cooper, and Southern Company, per stakeholder input

All fuel prices, as well as other price inputs like startup costs and O&M prices were converted to 2022$ using a 2% inflation factor

2030 Capacity Weighted Average Coal Price

Area	$/MMBtu
Duke	$3.34
Dominion SC	$4.22
Santee Cooper	$3.58
Southern Company	$3.34
Tennessee Valley Authority	$2.83
Associated Electric Coop.	$3.01
Lousiville Gas & Electric	$2.49
Power South Cooperative	$3.90
FL-SEEM Members	$3.90
Rest of Florida	$3.60
PJM	$2.97

Note: Prices shown in 2022$.

Operating Reserve Assumptions

VACAR-South reserve sharing group's reserve requirement allocations were modeled as individually held by each member utility, based on Advisory Board utility member feedback

- If these distinctions were not already present, we split total reserve requirements into regulation, spinning, and non-spinning reserves for consistency with other market areas
  - Adding a separate regulation requirement was intended to model future flexibility needs as more solar is deployed

We assumed generic regulation, spinning, and non-spinning reserve requirements, consistent with industry experience, for utilities outside of the Carolinas where no stakeholder or public data were available

PJM operating reserve requirements are based on current PJM market guidelines, with a nested reserve area structure representing deliverability constraints into the Mid-Atlantic Dominion (MAD) sub-zone

- Spinning reserves are held to cover the largest contingency, plus a 190 MW extended requirement
  - Source: David Kimmel. PJM Synchronized Reserve Overview. 2021
  - The largest contingency does not change in the Carolinas-in-PJM case, and the MW spinning reserve requirements remain the same. However, each load serving entity purchases less spinning capacity from the market due to increased total load
- We assume a regulation requirement equal to 1% of hourly demand to represent minute-to-minute system adjustments in the hourly market model. This percentage target does not change with the Carolinas joining PJM

Southeast RTO reserve requirements are assumed to match to PJM requirements (i.e. based on largest contingency) to avoid introducing modeling artefacts

Operating Reserve Assumptions By Market Structure

Some market reforms allow participants to hold or purchase fewer operating reserves

- We modeled the EIM as an energy-only market (no optimized reserve procurement)
  - Assumed EIM participation reduces BAs' load following reserve procurement due to regional diversity in load and renewables. Lower load following needs are based on reductions in real-time hour-to-hour net load variability in the market

RTOs have optimized operating reserve procurement

- Individual utilities purchase reserves from the market, based on their share of total market footprint demand
  - Blue entries at right denote market-based reserve procurement
  - Blue PJM block indicates that PJM (without Carolinas) is 78% of the expanded PJM + Carolinas market demand, and therefore procures only 78% of the requirement of the total combined RTO

Operating Reserve Requirement Inputs

BA	Reserve Type	2030 SQ/JDA Individual Rqts % of Peak Load	EIM Individual Rqts % of Peak Load	SERTO Procured From Mkt % of Peak Load	PJM Procured From Mkt % of Peak Load
Duke	*Regulation*	0.9%	1.0%	1.0%	1.0%
	Load Following	1.4%	1.3%	-	-
	*10-Min Synchronized**	1.5%	1.5%	0.9%	0.8%
Dominion	*Regulation*	1.0%	1.0%	1.0%	1.0%
	Load Following	1.4%	0.2%	-	-
	*10-Min Synchronized**	0.9%	0.9%	1.0%	0.8%
Santee Cooper	*Regulation*	1.0%	1.0%	1.0%	1.0%
	*Load Following***	6.4%	6.0%	-	-
	*10-Min Synchronized**	2.2%	2.2%	0.9%	0.8%
SERC/ FRCC	*Regulation*	1.0%	1.0%	1.0%	1.0%
	10-Min Synchronized	2.0%	1.9%	0.7%	1.9%
PJM (No CAR)	*Regulation*	1.0%	1.0%	1.0%	1.0%
	10-Min Synchronized	190 MW + Largest Contingency	190 MW + Largest Contingency	190 MW + Largest Contingency	78% of [190 MW + Largest Contingency]

** VACAR reserve sharing group allocations are assumed to be equal parts synchronized and non-synchronized requirements.*
*** Santee Cooper holds "Load Following" reserves during solar production hours only.*
Notes:
Blue entries denote market reserve procurement.
Non-spin and supplementary reserve requirements not shown, but are never limiting in the model.

Transmission Topology And Contract Path Transfer Limits

The dataset used in this model represents the physical transmission topology according to the 2018 Multiregional Modeling Working Group (MMWG) peak 2020 summer power flow case

- All network resources and generation is mapped to bus bars, which in turn are mapped to BAs

We implemented 2030 transmission upgrades according to best-available data from Advisory Board member utilities

Major interfaces and contingency constraints are included in the model, based on endogenous contingency analysis

- High-voltage transmission elements are monitored for violations in the model

In addition to physical transmission limits, we modeled typical available transfer capability (ATC) limits for non-firm, point-to-point transactions for available BA-to-BA contract paths in the region

- Carolina utilities' transfer limits are based on Advisory Board input
- Other utilities' limits are based on 90^{th} percentile of 2019-2021 net transfer data from the EIA-930 filing
- Trading with areas external to the simulated region (e.g., MISO, SPP, NYISO) is modeled on fixed schedules, based on 2020 hourly net interchange reported in EIA-930 filing

Trading Frictions

Transactions are charged OATT rates, trading margins, and administrative fees

- Non-firm transmission service rates are based on the most recent data from OASIS
  - We assume PJM charges a discounted $0.67/MWh rate for non-firm point-to-point transmission service to its border. Source: PJM Manual 27, revision 96 (12/21/2022), Section 6.1.2
  - SEEM transactions use available non-firm transmission capacity and do not incur OATT charges
  - JDA transactions likewise do not incur OATT charges
- SEEM administrative charges are based on SEEM cost-recovery mechanism
  - 75% of $2.8 million/year operating costs recovered through per-MWh charges (source: SEEM Agreement), levelized over 1.3 GWh average hourly trading volume reported in Guidehouse's SEEM cost-benefit analysis

Trading Friction Assumptions

OATT Rates	On-Peak 2022$/MWh	Off-Peak 2022$/MWh
DUKE	$3.86	$1.84
SCEG	$14.17	$6.75
SC	$8.09	$3.84
SOCO	$10.17	$4.84
TVA	$6.06	$2.89
AECI	$3.00	$2.00
LGEE	$2.00	$2.00
PS	$4.00	$4.00
PJM	$0.67	$0.67
DEF	$11.73	$5.58
SEC	$6.12	$2.91
TECO	$6.39	$3.04
JEA	$3.84	$3.84
CPL	$3.86	$1.84

Other Trading Frictions: Trade Type	Admin Fee 2022$/MWh	Margin 2022$/MWh
DA Bilateral (Non-RTO)	$ 1.00	$ 1.50
DA Bilateral (With RTO)	$ 1.00	$ 1.50
RT Bilateral (Non-RTO)	$ 1.00	$ 2.50
RT Bilateral (With RTO)	$ 1.00	$ 1.00
RTO-Internal	$ -	$ -
SEEM	$ 0.18	$ 0.91
JDA	$ 0.50	$ -

Note: Margins are per-participant (i.e. a trade would include a $3/MWh total trading margin friction component.

Market Reform Assumptions

Cycle	Status Quo	Carolinas JDA	EIM	Southeast RTO	Carolinas in PJM
Commitment					
DA	Utility-Specific	Utility-Specific	Utility-Specific	Pooled	Pooled
SEEM	Hold DA Commitment	Hold DA Commitment	-	-	-
RT	Utility-Specific Fast Start Commitment	Utility-Specific Fast Start Commitment	Pooled Fast Start Commitment	Pooled Fast Start Commitment	Pooled Fast Start Commitment
BA to BA Hurdles					
DA	OATT rate + $4 ED/$8 UC	OATT rate + $4 ED/$8 UC	OATT rate + $4 ED/$8 UC	No Hurdle	No Hurdle
SEEM	$2 hurdle	$2 hurdle	-	-	-
RT	OATT rate + $6 Non-RTO/$3 RTO Trades	$0.50 hurdle	No Hurdle	No Hurdle	No Hurdle
Transmission Capability					
DA	Based on Historical Usage	Based on Historical Usage	Based on Historical Usage	Physical Limits Only	Physical Limits Only
SEEM	Historical - DA trades	Historical - DA trades	-	-	-
RT	Historical - DA - SEEM	Historical - DA - SEEM	Physical Limits - DA Trades	Physical Limits Only	Physical Limits Only
Reserves					
	Utility-specific (w/ sharing groups)	Utility-specific (w/ sharing groups)	Utility-specific (w/ sharing groups, spin diversity benefit)	Market-wide sharing	Market-wide sharing
Look-Ahead (Hours)					
DA	48	48	48	48	48
SEEM	2	2	-	-	-
RT	2	2	2	2	2

2020 Benchmarking

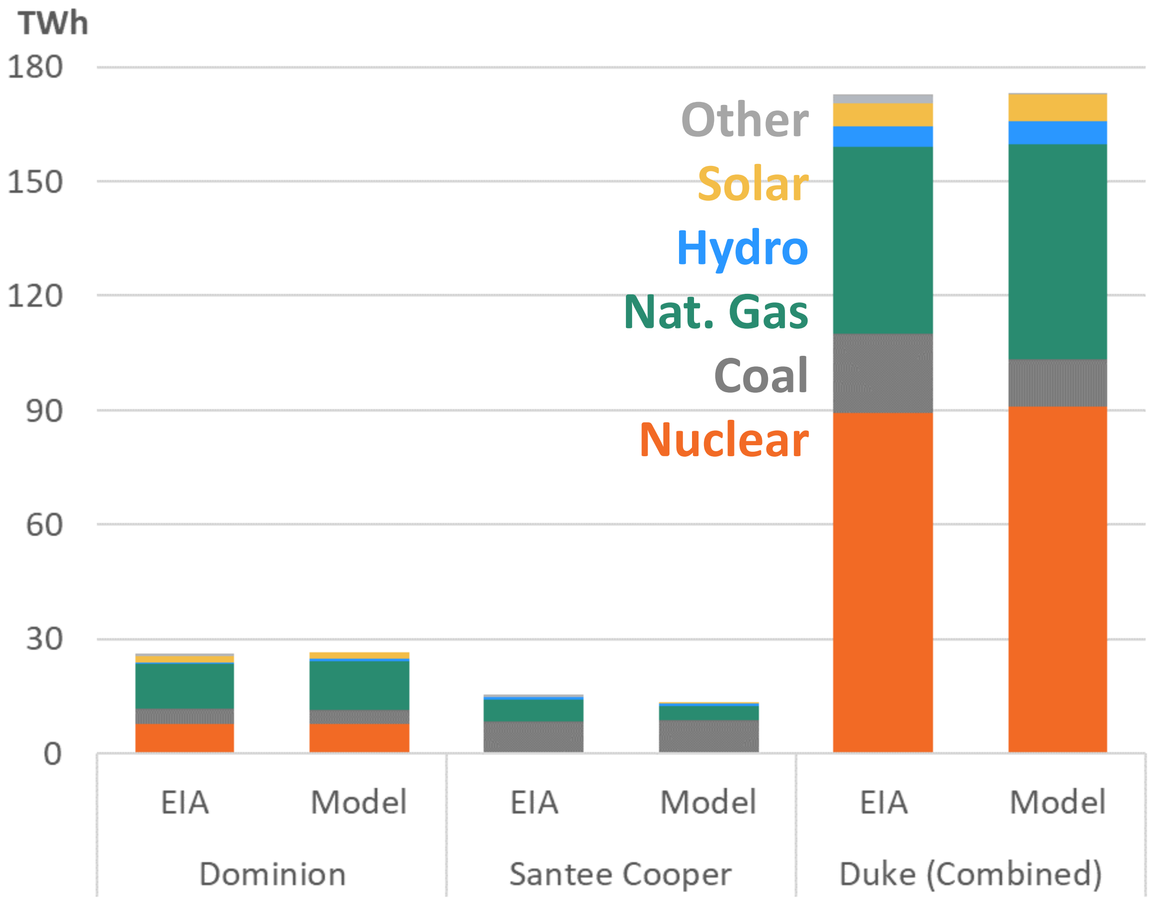
(Draft results as presented during December 19, 2022 Stakeholder meeting)

Carolina Generation Output by Resource Type

We benchmarked modeled generation against 2020 EIA Form 923 data

- Differences in total generation are due to trading
  - Santee Cooper imports slightly more
  - Duke exports slightly less
- SOCO coal is slightly cheaper and displaces Duke coal in the benchmark simulations (compared to actual generation)

Simulated 2020 Generation vs. Historical

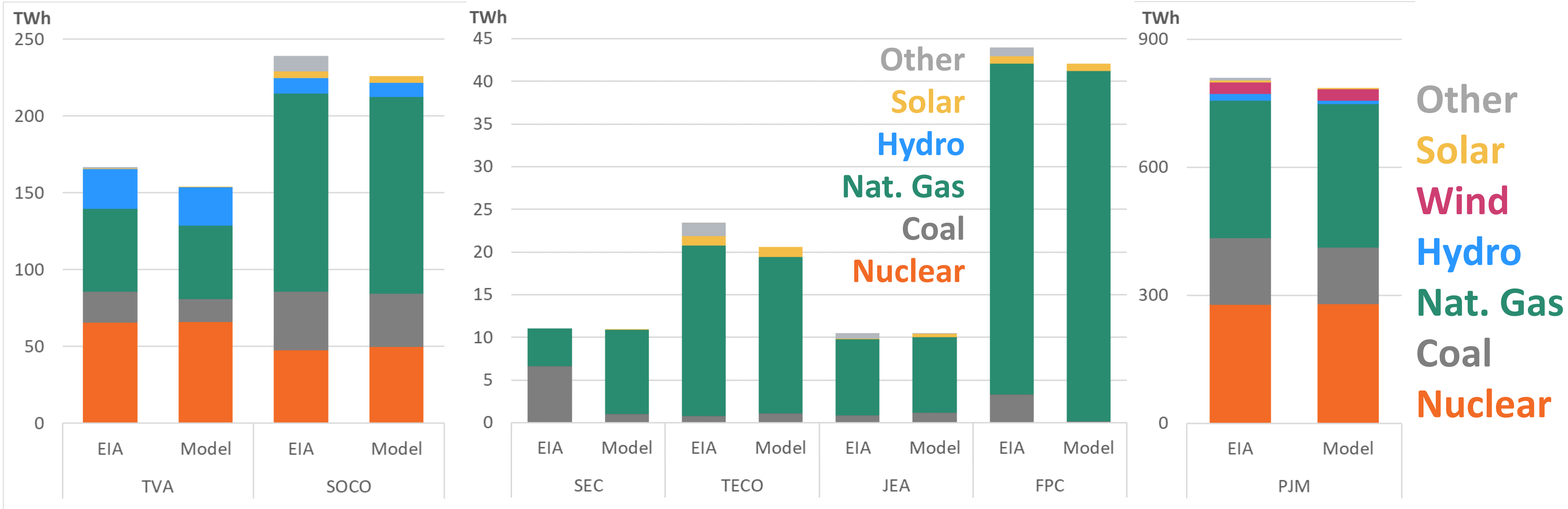


Note: Santee Cooper's stake in V. C. Summer nuclear plant is not represented out in this figure.

SERC and PJM Generation Output by Resource Type

Simulated generation output matches historical values well, with differences due to trading (including with regions outside the simulated footprint, such as MISO and SPP)

Modeled 2020 Generation Mix vs. Historical



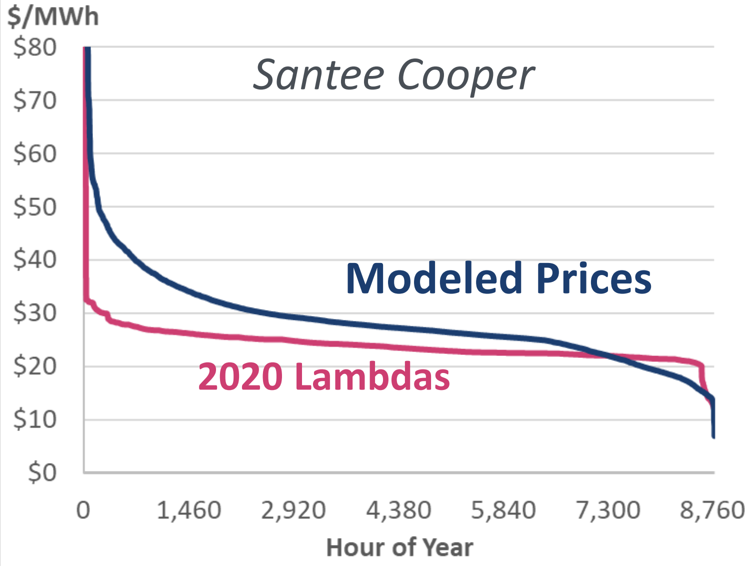
Carolina Energy Prices

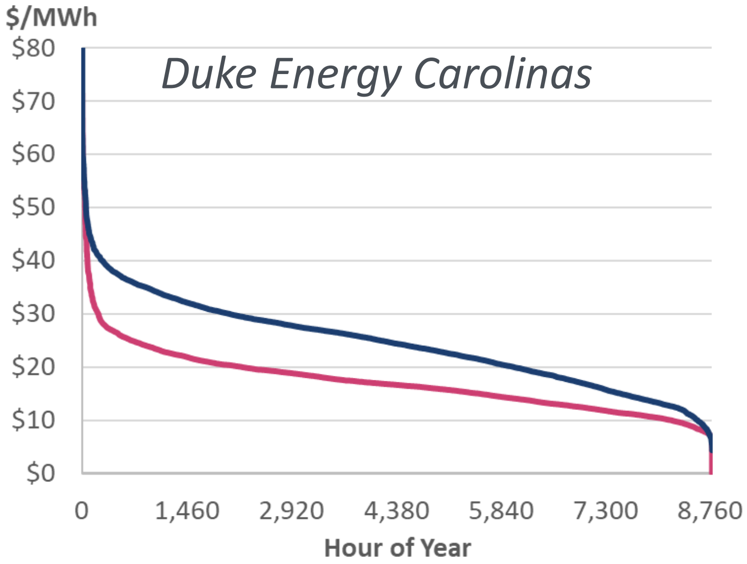
We benchmarked modeled day-ahead load-weighted average LMPs against system lambdas from FERC 714 filings

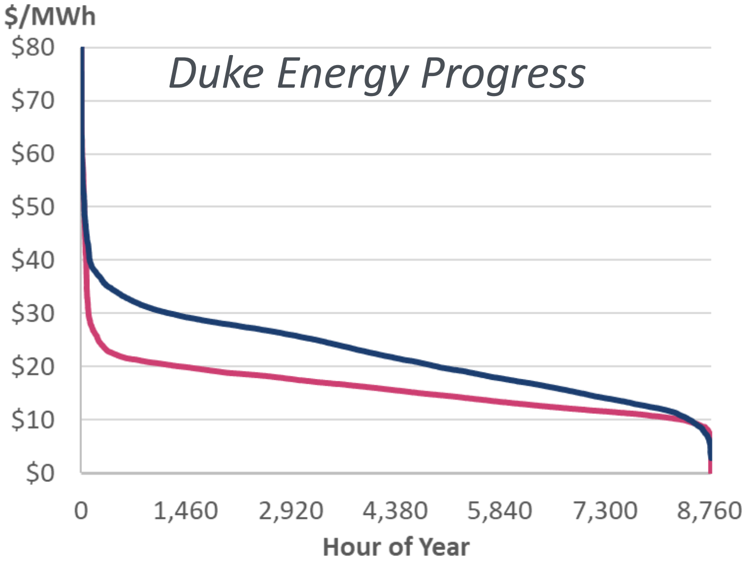
Santee Cooper modeled prices are higher than 2020 lambdas because the utility's import constraints (modeled consistent with Advisory Panel input) forces it to rely on its own, higher-cost generation

Some of the differences will be due to LMPs that (contrary to system lambdas) will reflect market interactions with neighboring systems

Modeled Prices vs. 2020 Lambdas

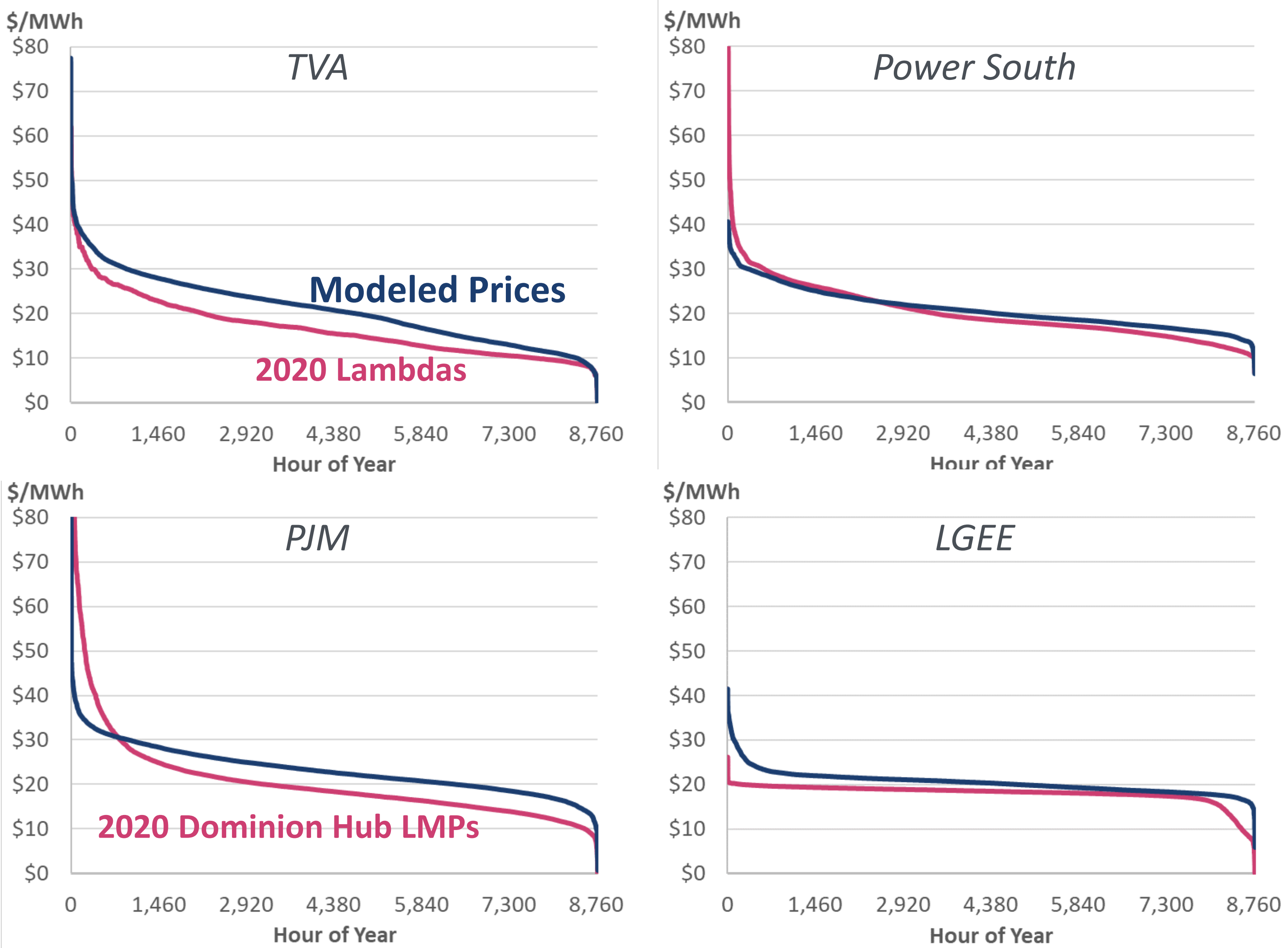






Energy Prices: SERC SEEM Members

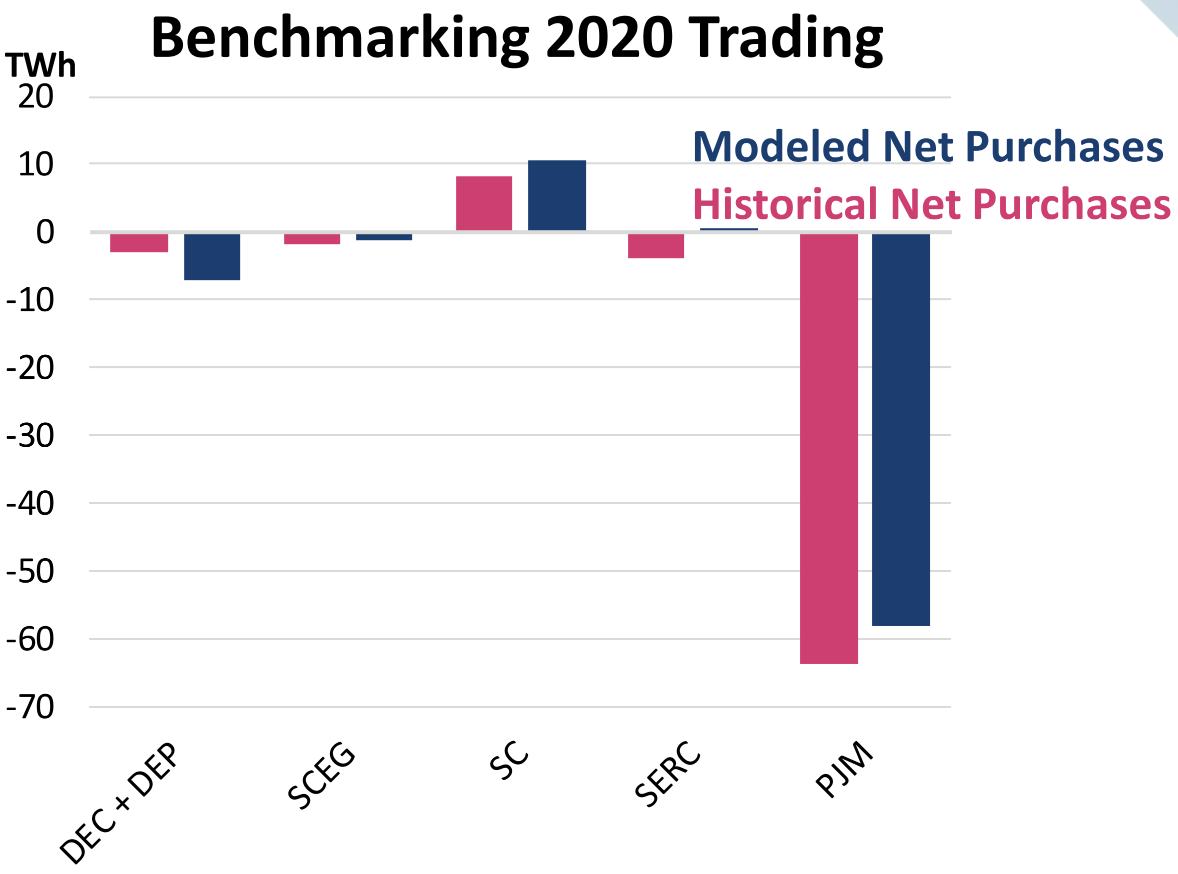
Modeled Prices vs. 2020 Lambdas



Simulated vs. Actual 2020 Trading

We benchmark modeled 2020 day-ahead trading against historical data

- Duke's modeled trades match historical values closely
- Santee Cooper imports more than historical
- TVA/SOCO discrepancies include effects from trades with MISO (not in the model footprint)
- PJM export volumes match historical well



Notes:
Positive values represent net imports, negative values are net exports. Historical data represent total loads from EIA-930 filings minus total generation reported in EIA-923 filings.

Model Improvements Since 12/19 Stakeholder Meeting

We updated the benchmarking case with feedback received after the stakeholder meeting on 12/19/2022

- Duke and Santee Cooper provided confidential 2020 fuel price data which were not reflected in public data. These inputs lowered the cost of generation for both utilities
- Santee Cooper indicated that they had recallable (discounted) transmission rights with Southern Company in 2020. Implementing these lower fees shifted Santee Cooper trading activity to rely more on Southern for imports

Beyond stakeholder-specific input updates, we also made several improvements for the 2020 back-casting and the 2030 forward-looking study simulations:

- Adjusted generation startup costs to omit long-term maintenance costs that were included as “cycling” costs
- Refined the representation of network topology
- Finalized the generation resource mapping
- Refined modelling of hydro resources
- Updated outages schedules for some units based on public data

2030 Market Simulation Results

2030 Generation Results – Total for Carolina Utilities

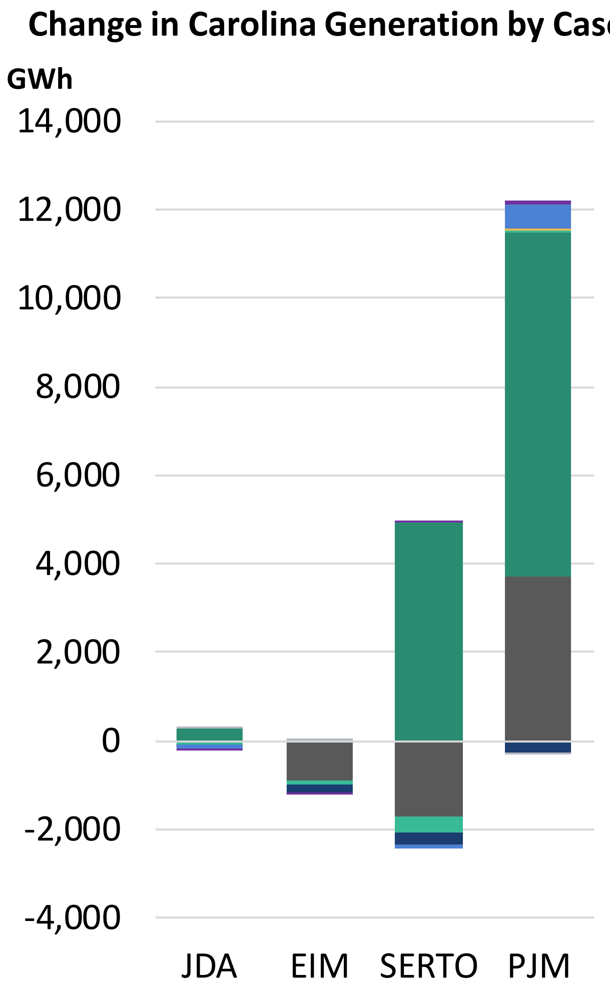
By 2030, almost two-thirds of South Carolina generation will come from very low marginal cost resources like nuclear and renewables

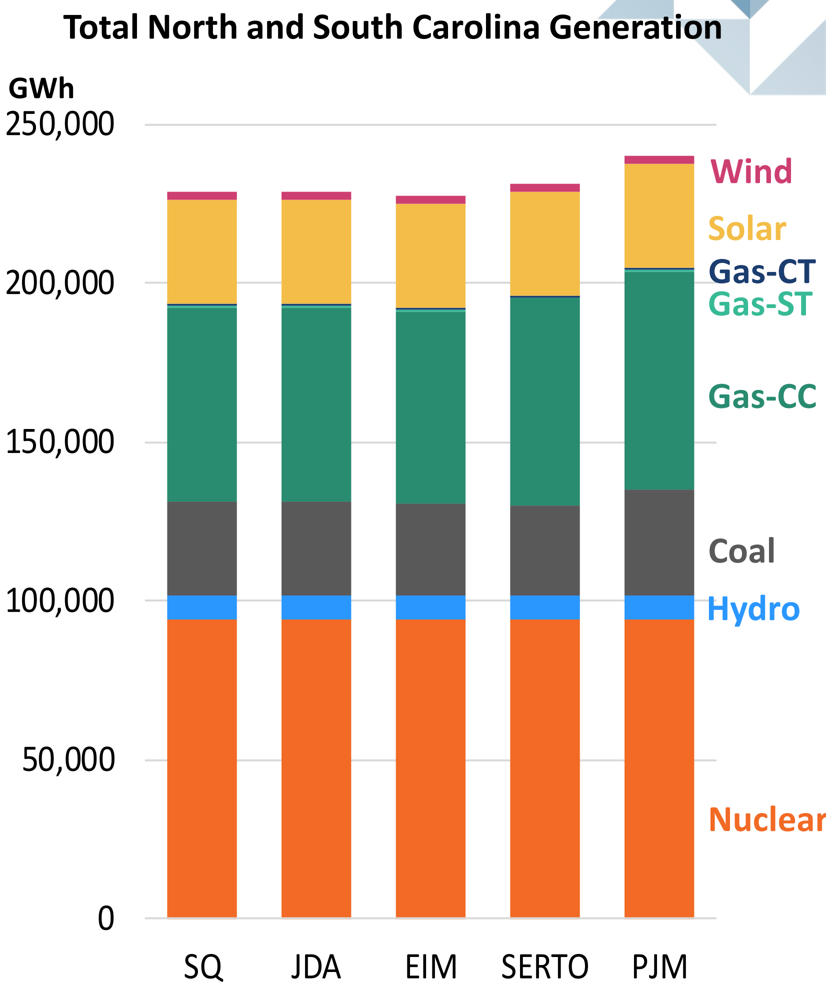
- Average cost of production will be around $15/MWh

The South Carolina utilities see minimal solar curtailments across market cases

Market integration increases South Carolina thermal generation because it is cost-competitive with neighboring regions, especially PJM

- South Carolina coal is less competitive than gas resources in the Southeast
- Both coal and gas are cost-competitive in PJM
- Reduced pumped hydro storage activity (shows up as positive generation difference) in PJM because larger resource and load diversity reduce need for storage





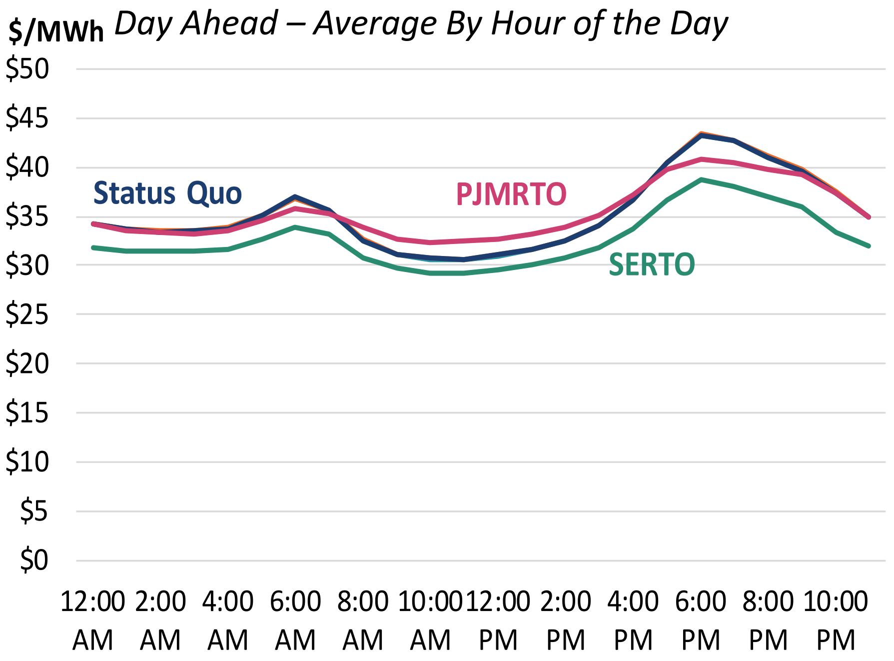
Note: Storage losses are minimal and are not shown.

Simulated 2030 Wholesale Energy Market Prices

Average energy prices drop in the Southeast RTO for the Carolinas, but increase in the PJM RTO case

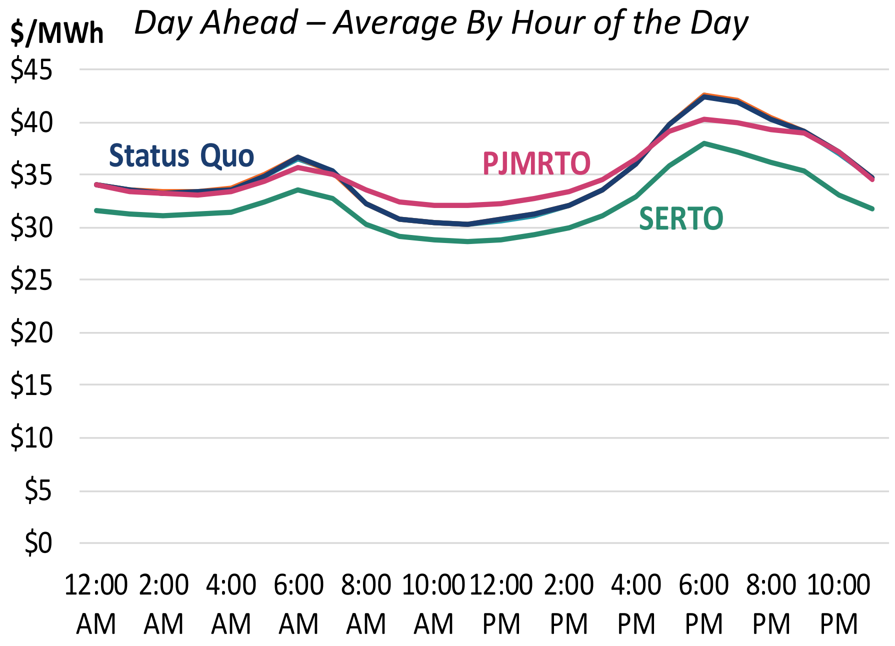
- The SERTO market allows the Carolinas to access inexpensive generation from other Southeast members, decreasing prices
- In the PJM market case, South Carolinas' energy prices equalize with the rest of the PJM market, remaining roughly similar, on average, as their status quo levels

Carolinas Load-Weighted Energy Prices



Notes: Includes all of Duke, Santee Cooper, and Dominion SC

Carolinas Generation-Weighted Energy Prices



Notes: Includes all of Duke, Santee Cooper, and Dominion SC

2030 Trading Volumes – Total of Carolina Utilities

Increasing market integration allows greater trading, thanks to optimized dispatch and lower hurdle rates

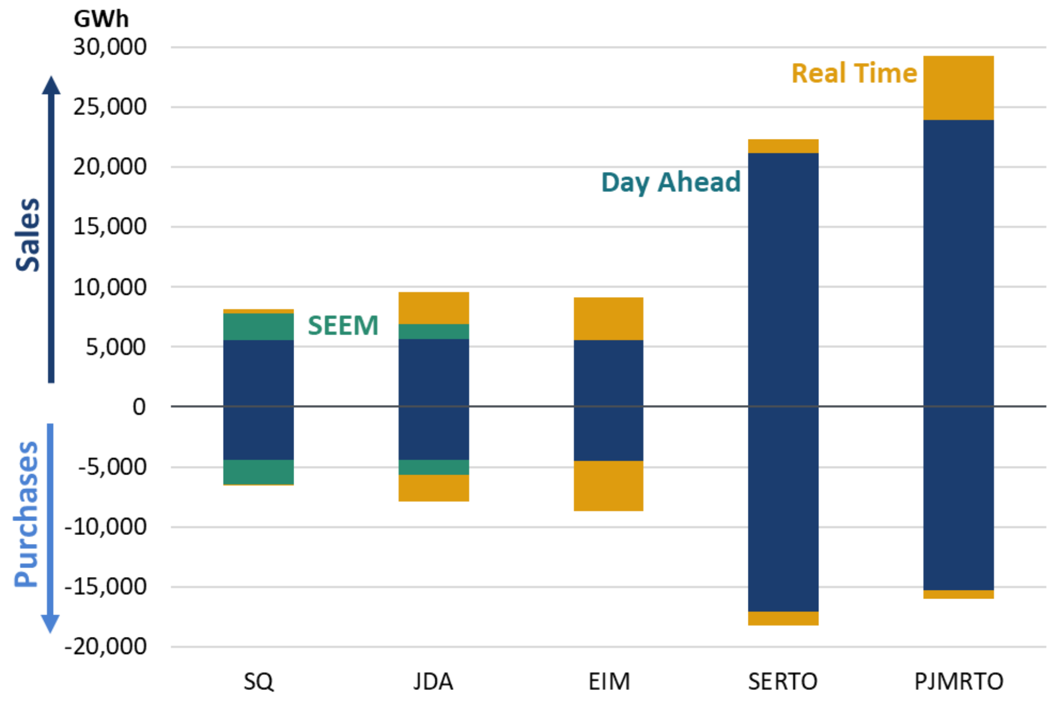
- SEEM trading accounts for just over 1% of total SEEM footprint demand in the Status Quo case, with minimal incremental transactions in real-time
- The Carolina utilities increase real-time trading volume under the JDA, and more so in the EIM

Joint commitment and day-ahead dispatch in the RTO cases enable significantly higher day-ahead trading than bilateral markets and utility-specific commitment

- Minor incremental real-time trading occurs to recover from forced generation outages
- Modeling forecast uncertainty would increase RTO real-time trading

South Carolina trades more in PJM than the SERTO because its generation is more cost-competitive in PJM

Carolina Utilities' Gross Trading by Case



SEEM Trading

Simulated SEEM trading volumes significantly exceed historically-observed SEEM trading volumes

- Simulated trading volumes are more than ten times larger than historically observed activity
- Actual volumes may grow through 2030 as members become comfortable with the platform

We calculate modeled SEEM trading volumes based on gross changes in balancing authority generation across the SEEM footprint between the day-ahead and SEEM optimization cycles

- For example, if Utility A generation in the SEEM optimization is 100 MWh lower than its generation in the day-ahead optimization, we count that utility as having purchased 100 MWh in the SEEM

Modeled vs. Historical SEEM Trading Volume

(Current SEEM members only, without new Florida joiners)

	Historical (2022-2023) *GWh*	Modeled (2030) *GWh*
November	23	474
December	40	508
January	47	588
February	36	420
March	38	435
Annual (Projected)	**481**	**5,818**

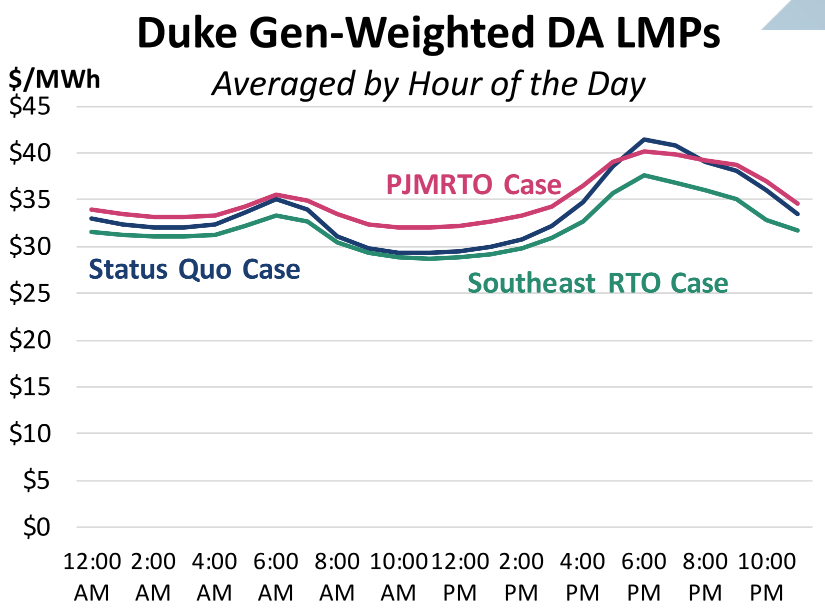
Additional Discussion of Duke Results

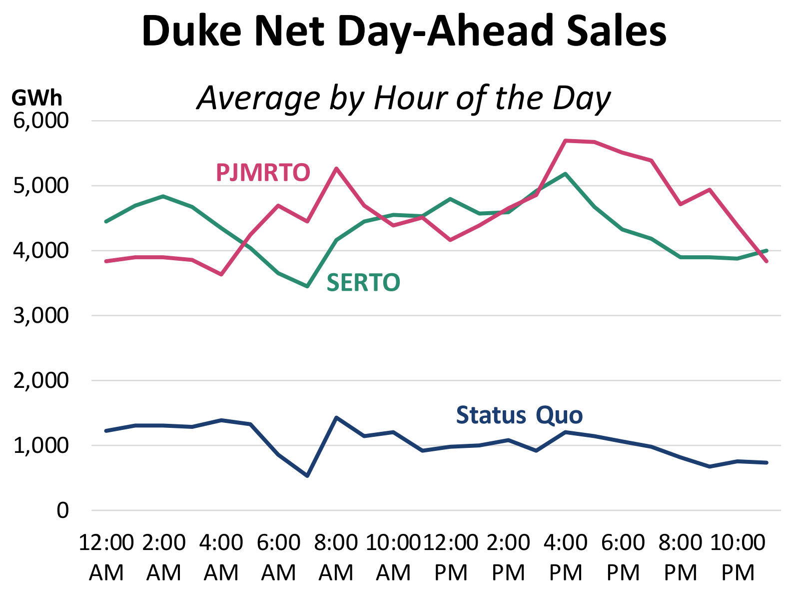
Our modeling shows Duke with a 2% increase in production costs in the SERTO case

- Prices vary among Southeastern BAs in the status quo
- Duke is a net exporter in the 2030 status quo case (and historically), with large profits on low-cost exports
- Without trading hurdles, Duke exports more in the RTO
- Duke earns lower profits on its exports because, due to significant solar and low-cost natural gas generation in the region, energy prices are equalized across the Southeast in SERTO (and lower than in the Status Quo and PJM cases)

Our modeling shows Duke as benefitting in the PJM case

- PJM energy prices are higher than Southeast prices
- Duke earns more in PJM market because its generation is cost-competitive, especially during high-priced evening hours
  - Evening trading is higher in PJM than the status quo thanks to the absence of trading frictions
- In PJM, Duke additionally profits by selling power to the Southeast, taking advantage of a lower export hurdle rate in PJM





Duke Heat Rates and Coal Generation

Duke's increased exports stem from its coal and gas CC facilities, which are some of the most efficient plants in the region

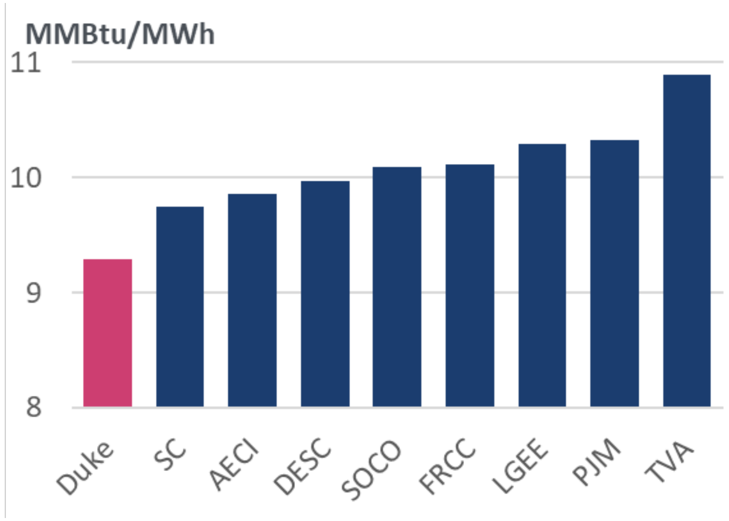
- Modeled heat rates are based on stakeholder and public data

Increases in Duke coal and gas generation enable decreases of coal generation in other balancing areas

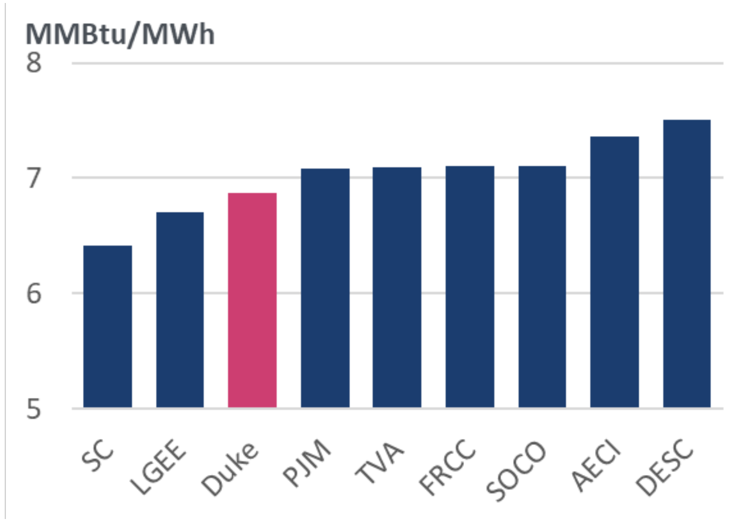
Simulated 2030 Annual Coal Generation By Market Reform Case

	Annual Coal Generation					Increase (Decrease) Relative to SQ			
	SQ	JDA	EIM	SERTO	PJMRTO	JDA	EIM	SERTO	PJMRTO
	TWh	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*	*TWh*
Duke	17.7	17.7	17.5	20.6	24.4	0.0	(0.1)	2.9	6.7
SC	6.7	6.8	6.7	3.5	3.3	0.0	0.0	(3.2)	(3.4)
DESC	4.7	4.7	4.7	3.7	3.6	0.0	(0.0)	(1.0)	(1.1)
Rest of SERC	72.2	72.4	72.2	76.4	71.8	0.2	(0.0)	4.1	(0.4)
FRCC	7.1	7.2	7.2	3.8	7.2	0.1	0.1	(3.4)	0.1
PJM	121.3	121.8	121.6	114.7	118.8	0.5	0.3	(6.5)	(2.5)
Total	**230**	**231**	**230**	**223**	**229**	**0.8**	**0.2**	**(7.1)**	**(0.7)**

Capacity-Weighted Average Coal Heat Rates



Capacity-Weighted Average Gas CC Heat Rates



Emissions Impacts of Market Reforms

More efficient generation under market-based optimal unit commitment and dispatch causes a redistribution of generation among market participants, reducing overall emissions

- Increases of more efficient Duke generation in the SERTO and PJMRTO cases increases emissions from Duke generation facilities, but reduces the dispatch of and emissions from less efficient generators in the regional footprint

Overall, market reforms result in lower emissions within the market footprint

Emissions by Market Reform Case

Area	Annual Emissions					Increase (Decrease) Relative to SQ			
	Base	**JDA**	**EIM**	**SERTO**	**PJM**	**JDA-SQ**	**EIM-SQ**	**SERTO-SQ**	**PJM-SQ**
	M Tons CO2	*M Tons CO2*	*M Tons CO2*	*M Tons CO2*	*M Tons CO2*	*M Tons CO2*	*M Tons CO2*	*M Tons CO2*	*M Tons CO2*
Duke	34.4	34.6	34.3	40.5	43.2	0.2	(0.1)	6.2	8.9
SC	11.5	11.3	10.9	8.5	7.9	(0.2)	(0.6)	(3.0)	(3.6)
DESC	9.3	9.2	8.9	5.3	6.9	(0.0)	(0.4)	(4.0)	(2.4)
Rest of SERC	153.6	153.8	154.2	162.0	152.5	0.2	0.6	8.4	(1.1)
FRCC	85.8	85.9	86.9	78.4	85.8	0.1	1.0	(7.4)	(0.0)
PJM	286.4	286.6	286.2	278.6	279.0	0.2	(0.1)	(7.8)	(7.4)

Notes: FRCC includes both SEEM and non-SEEM entities. PJM includes the present-day PJM footprint, without the Carolinas.

Overall 2030 Benefits

Evaluated Benefit Metrics:

- **"Adjusted Production Cost" (APC):** The operating costs of all units + purchase costs (at load LMP) – sales revenues (at gen LMP)
- **Wheeling Revenues:** The losses in transmission wheeling revenues associated with some market options
- **Market Settlements and Bilateral Trading Gains:** The change in value of trading gains from market and non-market transmission
  - In bilateral transactions, the difference between importer load LMP and exporter generation LMP, less trading frictions, is the "value of the trade" and is allocated equally to both parties
  - In market transactions, BA-internal congestion value is assumed to be refunded to load-serving entities

Total 2030 Generation Operating Cost Savings of Different Wholesale Market Options

(Relative to Status Quo)

Entity	JDA	EIM	SERTO	PJMRTO
Duke (SC portions)	$ 1	$ 2	$ (9)	$ 44
Dominion SC	$ 7	$ 6	$ 64	$ 74
Santee Cooper	$ 3	$ 16	$ 42	$ 64
South Carolina	**$ 12**	**$ 24**	**$ 96**	**$ 181**
Total Regional Market	$ 15	$ 99	$ 228	$ 322

Source/Notes:
[1]: Operational cost savings include changes in "adjusted production costs" (fuel and variable generation costs and market purchase costs net of off-system sales revenues), transmission "wheeling" revenues, and gains from bilateral trades and market-based congestion revenues (in EIM and RTO cases), both for transaction within regional footprints and external to them.
[2]: The Duke row shows only South Carolina benefits (21% of total company benefits, allocated based on load share). Duke's costs increase slightly in the Southeast RTO case in large part due to the company realizing lower wholesale market prices on its off-system sales in a Southeast RTO, as discussed further below and in Appendix B.
[3]: Total regional market benefits based on the regional market footprint analyzed in the case.
Update load share and table numbers.

Overall Benefits (Detailed)

		Market Reform Results					Delta Above (Below) Status Quo (Negative is Benefit)							
Cost Component	Unit	2030 SQ	JDA	EIM	SERTO	PJM RTO	JDA		EIM		SERTO		PJM RTO	
SC Adjusted	**Mln $**	**$1,809**	**$1,803**	**$1,797**	**$1,700**	**$1,616**	**$ 5.72**	**0.3%**	**$ 12.46**	**0.7%**	**$ 108.85**	**6.0%**	**$ 192.52**	**10.6%**
Total Production Cost														
Duke	Mln $	$ 2,341	$ 2,352	$ 2,339	$ 2,757	$ 2,807	$ (10.96)	-0.5%	$ 1.67	0.1%	$ (416)	-18%	$ (467)	-20%
Dominion	Mln $	$ 525	$ 523	$ 507	$ 245	$ 369	$ 1.86	0.4%	$ 18	3.4%	$ 280	53%	$ 155	30%
Santee Cooper	Mln $	$ 626	$ 620	$ 602	$ 505	$ 463	$ 5.86	0.9%	$ 24	3.8%	$ 122	19%	$ 163	26%
Revenue and Quantity of Sales (Purchases)														
Duke	Mln $	$ 156	$ 208	$ 196	$ 610	$ 905	$ 52	33%	$ 40	26%	$ 454	292%	$ 749	481%
Duke	GWh	(171)	(7)	(6)	(19)	(25)	165	-96%	152	-89%	171	-100%	336	-196%
Dominion	Mln $	$ (97)	$ (125)	$ (140)	$ (338)	$ (205)	$ (27)	28%	$ (42)	43%	$ (240)	247%	$ (107)	110%
Dominion	GWh	(25)	3.2	3.7	10	6.2	28	-113%	36	-142%	25	-100%	53	-213%
Santee Cooper	Mln $	$ (68)	$ (78)	$ (90)	$ (155)	$ (173)	$ (10)	14%	$ (87)	128%	$ 68	-100%	$ 58	-86%
Santee Cooper	GWh	(29)	1.7	2.2	4.7	5.4	30	-106%	31	-108%	33	-116%	34	-119%
Total Adjusted Production Cost														
Duke	Mln $	$ 2,142	$ 2,144	$ 2,143	$ 2,147	$ 1,903	$ (2.3)	-0.1%	$ (1.7)	-0.1%	$ (5)	-0.3%	$ 239	11.2%
Dominion	Mln $	$ 648	$ 648	$ 646	$ 583	$ 574	$ 0.7	0.1%	$ 2.0	0.3%	$ 66	10%	$ 74	11.5%
Santee Cooper	Mln $	$ 704	$ 698	$ 693	$ 659	$ 637	$ 5.5	0.8%	$ 11	1.5%	$ 44	6.3%	$ 67	9.5%
Gains from Trade														
Duke	Mln $	$ 27	$ 32	$ 34	$ 4.3	$ 9	$ (5.3)	-19.9%	$ (7.3)	-27.1%	$ 23	84%	$ 17	65.3%
Dominion	Mln $	$ 5.9	$ 13	$ 10	$ -	$ 0.4	$ (6.8)	-115%	$ (4.3)	-73.3%	$ 6	100%	$ 5	92.7%
Santee Cooper	Mln $	$ 9	$ 6.9	$ 15	$ -	$ 1.6	$ 2.2	24.4%	$ (5.4)	-58.9%	$ 9	100%	$ 8	82.4%
Wheeling Revenues														
Duke	Mln $	$ 21	$ 22	$ 24	$ 17	$ 1.3	$ (0.75)	-3.5%	$ (3.0)	-14.1%	$ 4.8	23%	$ 20	93.7%
Dominion	Mln $	$ 0.1	$ 0.0	$ 0.0	$ -	$ 0.1	$ 0.01	13.3%	$ 0.01	11.4%	$ 0.06	100%	$ (0.06)	-99.7%
Santee Cooper	Mln $	$ 0.7	$ 0.7	$ 0.7	$ -	$ 0.4	$ 0.02	3.4%	$ 0.01	1.9%	$ 0.71	100%	$ 0.29	41.0%

How to Read "Adjusted Production Cost" Tables

The tables on the following slides compare production/trading volumes and average/total costs across scenarios

- **Panel 1** shows the total production and transaction volumes across each case and market type
- **Panel 2** shows the average cost of production, and the average cost of sales and purchases across all hours when a utility trades
- **Panel 3** shows the total cost or revenue credited to the utility or footprint
- Total production cost savings are the sum of utility costs and revenues. Costs are production cost and purchase costs (rows 1, 2, 3, 4, and 5). Revenues are rows 6, 7, 8, and 9. **Row 10, the total of adjusted production cost =[1] + [3 - 5] – [7 - 9]**

Example: Adjusted Production Cost for the Carolina Utilities – Southeast RTO Results

		Panel 1: Volumes			Panel 2: Prices			Panel 3: Dollars			
		GWh			$/MWh			Total ($1000s/Year)			Green = (+) in benefit Red = (-) in benefit
Cost Components	**Row**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**	
Production	[1]	226,876	229,417	**2,542**	$15.39	$15.29	**-$0.10**	3,491,679	3,506,761	**$15,082**	(Cost Increase)
Purchases	[2]										
Bilateral/Day-Ahead Market	[3]	4,450	17,041	**12,591**	$43.77	$32.71	**-$11.06**	194,793	557,463	**$362,670**	(Cost Increase)
SEEM Market	[4]	2,028	-	**-2,028**	$39.19	-	**NA**	79,459	-	**-$79,459**	(Cost Savings)
Real-Time Market	[5]	74	1,141	**1,066**	$55.67	$36.60	**-$19.07**	4,137	41,752	**$37,615**	
Sales	[6]										
Bilateral/Day-Ahead Market	[7]	5,543	21,116	**15,572**	$33.43	$31.93	**-$1.50**	185,328	674,194	**$488,866**	(Revenue Increase)
SEEM Market	[8]	2,228	-	**-2,228**	$33.78	-	**NA**	75,253	-	**-$75,253**	(Revenue Loss)
Real-Time Market	[9]	392	1,218	**826**	$40.54	$35.10	**-$5.44**	15,876	42,739	**$26,863**	
Total	[10]	**225,265**	**225,265**	**0**	**$15.51**	**$15.04**	**-$0.46**	3,493,610	3,389,043	**-$104,567**	(Absolute Benefit)
% Change in APC	[11]									***-3.0%***	(Relative Benefit)

Note: Per-MWh costs in row [1] represent average production costs. Purchase prices in rows [3]-[5] represent BA load-weighted LMPs averaged across all net purchase hours. Sales prices in rows [7]-[9] represent generation-weighted LMPs averaged across all net sales hours.

JDA Benefits

JDA vs. Status Quo: 2030 Results

Entity	APC Benefit ($ Millions)	Wheeling Revenue Benefit ($ Millions)	Trading Gain Benefit ($ Millions)	Net Benefit ($ Millions)	Net Benefit (% of SQ APC)
Duke (SC portions)	-$0.5	$0.2	$1.1	$0.8	0.2%
Santee Cooper	$5.5	$0.0	-$2.2	$3.3	0.5%
Dominion SC	$0.7	$0.0	$6.8	$7.4	1.1%
South Carolina	**$5.7**	**$0.1**	**$5.7**	**$11.5**	**0.6%**
Total Carolinas	$3.9	$0.7	$9.9	$14.5	0.4%
Total Regional Market	$3.9	$0.7	$9.9	$14.5	0.4%

Adjusted Production Cost for the Carolina Utilities

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Row**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**
Production	[1]	226,876	226,968	**93**	$15.39	$15.40	**$0.01**	3,491,679	3,494,920	**$3,241**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	4,450	4,431	**-19**	$43.77	$43.67	**-$0.10**	194,793	193,530	**-$1,263**
SEEM Market	[4]	2,028	3,227	**1,200**	$39.19	$37.23	**-$1.96**	79,459	120,155	**$40,697**
Real-Time Market	[5]	74	245	**171**	$55.67	$34.80	**-$20.87**	4,137	8,538	**$4,401**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,543	5,627	**84**	$33.43	$33.30	**-$0.13**	185,328	187,385	**$2,057**
SEEM Market	[8]	2,228	3,231	**1,003**	$33.78	$34.41	**$0.63**	75,253	111,183	**$35,930**
Real-Time Market	[9]	392	749	**358**	$40.54	$38.58	**-$1.96**	15,876	28,900	**$13,025**
Total	[10]	**225,265**	**225,265**	**0**	**$15.51**	**$15.49**	**-$0.02**	3,493,610	3,489,674	**-$3,936**
% Change in APC	[11]									***-0.1%***

Note: Adjusted production cost table includes the entire footprints of Duke, Santee Cooper, and Dominion SC.

JDA Benefits

Adjusted Production Cost: Duke

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Row**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**
Production	[1]	177,789	178,102	**313**	$13.17	$13.20	**$0.04**	2,340,667	2,351,624	**$10,957**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	603	628	**25**	$42.71	$43.13	**$0.42**	25,752	27,098	**$1,347**
SEEM Market	[4]	825	879	**55**	$43.63	$43.00	**-$0.62**	35,976	37,811	**$1,835**
Real-Time Market	[5]	4	191	**187**	$49.90	$34.39	**-$15.51**	178	6,554	**$6,375**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,434	5,515	**81**	$33.41	$33.28	**-$0.13**	181,550	183,538	**$1,988**
SEEM Market	[8]	1,911	2,440	**529**	$33.37	$33.34	**-$0.03**	63,773	81,346	**$17,573**
Real-Time Market	[9]	385	355	**-30**	$40.61	$40.29	**-$0.33**	15,632	14,314	**-$1,318**
Total	[10]	**171,490**	**171,490**	**0**	**$12.49**	**$12.50**	**$0.01**	2,141,618	2,143,888	**$2,270**
% Change in APC	[11]									***0.1%***

Adjusted Production Cost: Dominion

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Row**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**
Production	[1]	21,936	21,855	**-80**	$23.93	$23.93	**$0.00**	524,809	522,951	**-$1,858**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	2,361	2,343	**-18**	$41.35	$41.21	**-$0.14**	97,625	96,547	**-$1,078**
SEEM Market	[4]	886	1,169	**283**	$34.40	$34.33	**-$0.07**	30,478	40,127	**$9,649**
Real-Time Market	[5]	1	35	**34**	$61.80	$36.41	**-$25.39**	34	1,256	**$1,223**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	6	5	**-1**	$46.74	$48.34	**$1.59**	266	223	**-$43**
SEEM Market	[8]	99	150	**51**	$42.92	$43.88	**$0.95**	4,240	6,573	**$2,333**
Real-Time Market	[9]	0	169	**168**	$67.57	$37.62	**-$29.95**	18	6,349	**$6,330**
Total	[10]	**25,078**	**25,078**	**0**	**$25.86**	**$25.83**	**-$0.03**	648,422	647,736	**-$685**
% Change in APC	[11]									***-0.1%***

Adjusted Production Cost: Santee Cooper

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Row**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**
Production	[1]	27,151	27,011	**-140**	$23.06	$22.97	**-$0.10**	626,202	620,345	**-$5,857**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	1,486	1,460	**-26**	$48.05	$47.86	**-$0.19**	71,416	69,884	**-$1,532**
SEEM Market	[4]	317	1,179	**862**	$41.00	$35.79	**-$5.21**	13,005	42,218	**$29,213**
Real-Time Market	[5]	70	20	**-50**	$55.92	$35.96	**-$19.96**	3,925	728	**-$3,197**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	103	107	**4**	$33.97	$33.82	**-$0.16**	3,512	3,624	**$112**
SEEM Market	[8]	217	641	**424**	$33.29	$36.28	**$2.99**	7,240	23,264	**$16,024**
Real-Time Market	[9]	6	225	**219**	$34.88	$36.59	**$1.71**	226	8,238	**$8,012**
Total	[10]	**28,697**	**28,697**	**0**	**$24.52**	**$24.32**	**-$0.19**	703,570	698,050	**-$5,521**
% Change in APC	[11]									***-0.8%***

EIM Benefits

EIM vs. Status Quo: 2030 Results

Entity	APC Benefit ($ Millions)	Wheeling Revenue Benefit ($ Millions)	Trading Gain Benefit ($ Millions)	Net Benefit ($ Millions)	Net Benefit (% of SQ APC)
Duke (SC portions)	-$0.4	$0.6	$1.5	$1.8	0.4%
Santee Cooper	$10.9	$0.0	$5.4	$16.2	2.3%
Dominion SC	$2.0	$0.0	$4.3	$6.3	1.0%
South Carolina	**$12.5**	**$0.6**	**$11.2**	**$24.3**	**1.3%**
Total Carolinas	$11.2	$3.0	$17.0	$31.1	0.9%
Total Regional Market	$41.5	-$5.2	$62.3	$98.7	0.7%

Adjusted Production Cost for the Carolina Utilities

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Row**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**
Production	[1]	226,876	225,690	**-1,186**	$15.39	$15.28	**-$0.11**	3,491,679	3,448,439	**-$43,240**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	4,450	4,479	**29**	$43.77	$43.54	**-$0.23**	194,793	195,054	**$262**
SEEM Market	[4]	2,028	-	**-2,028**	$39.19	-	**NA**	79,459	-	**-$79,459**
Real-Time Market	[5]	74	4,248	**4,174**	$55.67	$34.00	**-$21.67**	4,137	144,423	**$140,286**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,543	5,581	**38**	$33.43	$33.33	**-$0.10**	185,328	186,021	**$693**
SEEM Market	[8]	2,228	-	**-2,228**	$33.78	-	**NA**	75,253	-	**-$75,253**
Real-Time Market	[9]	392	3,571	**3,179**	$40.54	$33.45	**-$7.09**	15,876	119,450	**$103,575**
Total	[10]	**225,265**	**225,265**	**0**	**$15.51**	**$15.46**	**-$0.05**	3,493,610	3,482,445	**-$11,165**
% Change in APC	[11]									***-0.3%***

Note: Adjusted production cost table includes the entire footprints of Duke, Santee Cooper, and Dominion SC.

EIM Benefits

Adjusted Production Cost: Duke

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	177,789	177,760	**-29**	$13.17	$13.16	**-$0.01**	2,340,667	2,338,996	**-$1,671**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	603	624	**21**	$42.71	$43.05	**$0.34**	25,752	26,874	**$1,122**
SEEM Market	[4]	825	-	**-825**	$43.63	-	**NA**	35,976	-	**-$35,976**
Real-Time Market	[5]	4	1,214	**1,210**	$49.90	$37.63	**-$12.27**	178	45,670	**$45,492**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,434	5,468	**34**	$33.41	$33.30	**-$0.10**	181,550	182,100	**$550**
SEEM Market	[8]	1,911	-	**-1,911**	$33.37	-	**NA**	63,773	-	**-$63,773**
Real-Time Market	[9]	385	2,641	**2,256**	$40.61	$32.63	**-$7.98**	15,632	86,171	**$70,540**
Total	[10]	**171,490**	**171,490**	**0**	**$12.49**	**$12.50**	**$0.01**	2,141,618	2,143,269	**$1,651**
% Change in APC	[11]									***0.1%***

Adjusted Production Cost: Dominion

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	21,936	21,391	**-544**	$23.93	$23.70	**-$0.23**	524,809	506,948	**-$17,861**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	2,361	2,376	**15**	$41.35	$41.45	**$0.11**	97,625	98,508	**$883**
SEEM Market	[4]	886	-	**-886**	$34.40	-	**NA**	30,478	-	**-$30,478**
Real-Time Market	[5]	1	1,503	**1,502**	$61.80	$32.28	**-$29.52**	34	48,508	**$48,474**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	6	5	**-1**	$46.74	$45.47	**-$1.28**	266	228	**-$39**
SEEM Market	[8]	99	-	**-99**	$42.92	-	**NA**	4,240	-	**-$4,240**
Real-Time Market	[9]	0	187	**187**	$67.57	$38.86	**-$28.71**	18	7,273	**$7,255**
Total	[10]	**25,078**	**25,078**	**0**	**$25.86**	**$25.78**	**-$0.08**	648,422	646,464	**-$1,958**
% Change in APC	[11]									***-0.3%***

Adjusted Production Cost: Santee Cooper

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	27,151	26,539	**-613**	$23.06	$22.70	**-$0.36**	626,202	602,495	**-$23,708**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	1,486	1,479	**-7**	$48.05	$47.12	**-$0.94**	71,416	69,673	**-$1,743**
SEEM Market	[4]	317	-	**-317**	$41.00	-	**NA**	13,005	-	**-$13,005**
Real-Time Market	[5]	70	1,532	**1,461**	$55.92	$32.81	**-$23.11**	3,925	50,244	**$46,320**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	103	109	**5**	$33.97	$34.03	**$0.06**	3,512	3,693	**$181**
SEEM Market	[8]	217	-	**-217**	$33.29	-	**NA**	7,240	-	**-$7,240**
Real-Time Market	[9]	6	743	**737**	$34.88	$35.00	**$0.12**	226	26,006	**$25,780**
Total	[10]	**28,697**	**28,697**	**0**	**$24.52**	**$24.14**	**-$0.38**	703,570	692,712	**-$10,858**
% Change in APC	[11]									***-1.5%***

Southeast RTO Benefits

SERTO vs. Status Quo: 2030 Results

Entity	APC Benefit ($ Millions)	Wheeling Revenue Benefit ($ Millions)	Trading Gain Benefit ($ Millions)	Net Benefit ($ Millions)	Net Benefit (% of SQ APC)
Duke (SC portions)	-$1.2	-$1.2	-$6.9	-$9.3	-2.0%
Santee Cooper	$44.3	$1.9	-$4.5	$41.7	5.8%
Dominion SC	$65.7	$2.2	-$4.0	$64.0	9.8%
South Carolina	**$108.9**	**$2.9**	**-$15.4**	**$96.4**	**5.3%**
Total Carolinas	$104.6	-$1.6	-$40.8	$62.2	1.8%
Total Regional Market	$371.4	$8.8	-$152.4	$227.8	1.5%

Adjusted Production Cost for the Carolina Utilities

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Row**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**
Production	[1]	226,876	229,417	**2,542**	$15.39	$15.29	**-$0.10**	3,491,679	3,506,761	**$15,082**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	4,450	17,041	**12,591**	$43.77	$32.71	**-$11.06**	194,793	557,463	**$362,670**
SEEM Market	[4]	2,028	-	**-2,028**	$39.19	-	**NA**	79,459	-	**-$79,459**
Real-Time Market	[5]	74	1,141	**1,066**	$55.67	$36.60	**-$19.07**	4,137	41,752	**$37,615**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,543	21,116	**15,572**	$33.43	$31.93	**-$1.50**	185,328	674,194	**$488,866**
SEEM Market	[8]	2,228	-	**-2,228**	$33.78	-	**NA**	75,253	-	**-$75,253**
Real-Time Market	[9]	392	1,218	**826**	$40.54	$35.10	**-$5.44**	15,876	42,739	**$26,863**
Total	[10]	**225,265**	**225,265**	**0**	**$15.51**	**$15.04**	**-$0.46**	3,493,610	3,389,043	**-$104,567**
% Change in APC	[11]									*-3.0%*

Note: Adjusted production cost table includes the entire footprints of Duke, Santee Cooper, and Dominion SC.

SERTO Benefits

Adjusted Production Cost: Duke

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	Row	Status Quo	Market	Difference	Status Quo	Market	Difference	Status Quo	Market	Difference
Production	[1]	177,789	190,777	**12,988**	$13.17	$14.45	**$1.29**	2,340,667	2,757,133	**$416,466**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	603	1,286	**683**	$42.71	$34.39	**-$8.32**	25,752	44,219	**$18,467**
SEEM Market	[4]	825	-	**-825**	$43.63	-	**NA**	35,976	-	**-$35,976**
Real-Time Market	[5]	4	889	**886**	$49.90	$36.82	**-$13.08**	178	32,744	**$32,565**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,434	20,646	**15,212**	$33.41	$31.92	**-$1.49**	181,550	658,997	**$477,447**
SEEM Market	[8]	1,911	-	**-1,911**	$33.37	-	**NA**	63,773	-	**-$63,773**
Real-Time Market	[9]	385	816	**431**	$40.61	$34.35	**-$6.27**	15,632	28,034	**$12,402**
Total	[10]	**171,490**	**171,490**	**0**	**$12.49**	**$12.52**	**$0.03**	2,141,618	2,147,064	**$5,446**
% Change in APC	[11]									***0.3%***

Adjusted Production Cost: Dominion

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	Row	Status Quo	Market	Difference	Status Quo	Market	Difference	Status Quo	Market	Difference
Production	[1]	21,936	14,626	**-7,309**	$23.93	$16.75	**-$7.18**	524,809	244,950	**-$279,859**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	2,361	10,627	**8,266**	$41.35	$32.35	**-$9.00**	97,625	343,804	**$246,179**
SEEM Market	[4]	886	-	**-886**	$34.40	-	**NA**	30,478	-	**-$30,478**
Real-Time Market	[5]	1	84	**84**	$61.80	$33.64	**-$28.16**	34	2,840	**$2,806**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	6	79	**73**	$46.74	$27.22	**-$19.53**	266	2,153	**$1,886**
SEEM Market	[8]	99	-	**-99**	$42.92	-	**NA**	4,240	-	**-$4,240**
Real-Time Market	[9]	0	181	**180**	$67.57	$37.40	**-$30.17**	18	6,759	**$6,741**
Total	[10]	**25,078**	**25,078**	**0**	**$25.86**	**$23.23**	**-$2.62**	648,422	582,682	**-$65,740**
% Change in APC	[11]									***-10.1%***

Adjusted Production Cost: Santee Cooper

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	Row	Status Quo	Market	Difference	Status Quo	Market	Difference	Status Quo	Market	Difference
Production	[1]	27,151	24,014	**-3,137**	$23.06	$21.02	**-$2.05**	626,202	504,678	**-$121,524**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	1,486	5,128	**3,641**	$48.05	$33.04	**-$15.01**	71,416	169,440	**$98,024**
SEEM Market	[4]	317	-	**-317**	$41.00	-	**NA**	13,005	-	**-$13,005**
Real-Time Market	[5]	70	167	**97**	$55.92	$36.93	**-$18.99**	3,925	6,168	**$2,244**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	103	391	**287**	$33.97	$33.40	**-$0.57**	3,512	13,044	**$9,532**
SEEM Market	[8]	217	-	**-217**	$33.29	-	**NA**	7,240	-	**-$7,240**
Real-Time Market	[9]	6	221	**214**	$34.88	$35.99	**$1.11**	226	7,945	**$7,720**
Total	[10]	**28,697**	**28,697**	**0**	**$24.52**	**$22.97**	**-$1.54**	703,570	659,297	**-$44,274**
% Change in APC	[11]									***-6.3%***

PJM Benefits of Market Participation by Carolina Utilities

PJM vs. Status Quo: 2030 Results

Entity	APC Benefit ($ Millions)	Wheeling Revenue Benefit ($ Millions)	Trading Gain Benefit ($ Millions)	Net Benefit ($ Millions)	Net Benefit (% of SQ APC)
Duke (SC portions)	$51.0	-$4.5	-$2.3	$44.2	9.7%
Santee Cooper	$67.1	-$0.6	-$2.9	$63.5	9.0%
Dominion SC	$74.5	$0.0	-$0.8	$73.7	11.4%
South Carolina	**$192.5**	**-$5.1**	**-$5.9**	**$181.5**	**10.0%**
Total Carolinas	$380.4	-$21.6	-$14.3	$344.5	9.9%
Total Regional Market	$367.8	-$20.6	-$25.6	$321.6	1.8%

Adjusted Production Cost for the Carolina Utilities

		GWh			$/MWh			Total ($1000s/Year)		
Cost Components	**Row**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**	**Status Quo**	**Market**	**Difference**
Production	[1]	226,876	238,809	**11,934**	$15.39	$15.24	**-$0.15**	3,491,679	3,640,001	**$148,323**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	4,450	15,274	**10,823**	$43.77	$33.87	**-$9.90**	194,793	517,290	**$322,497**
SEEM Market	[4]	2,028	-	**-2,028**	$39.19	-	**NA**	79,459	-	**-$79,459**
Real-Time Market	[5]	74	715	**641**	$55.67	$38.78	**-$16.90**	4,137	27,730	**$23,593**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,543	24,157	**18,614**	$33.43	$36.07	**$2.64**	185,328	871,445	**$686,117**
SEEM Market	[8]	2,228	-	**-2,228**	$33.78	-	**NA**	75,253	-	**-$75,253**
Real-Time Market	[9]	392	5,376	**4,984**	$40.54	$37.28	**-$3.26**	15,876	200,382	**$184,506**
Total	[10]	**225,265**	**225,265**	**0**	**$15.51**	**$13.82**	**-$1.69**	3,493,610	3,113,194	**-$380,416**
% Change in APC	[11]									***-10.9%***

Note: Adjusted production cost table includes the entire footprints of Duke, Santee Cooper, and Dominion SC.

PJM Benefits

Adjusted Production Cost: Duke

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	177,789	196,616	**18,827**	$13.17	$14.28	**$1.11**	2,340,667	2,807,251	**$466,584**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	603	1,430	**827**	$42.71	$35.25	**-$7.46**	25,752	50,408	**$24,656**
SEEM Market	[4]	825	-	**-825**	$43.63	-	**NA**	35,976	-	**-$35,976**
Real-Time Market	[5]	4	501	**497**	$49.90	$39.44	**-$10.46**	178	19,755	**$19,577**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	5,434	23,665	**18,231**	$33.41	$35.98	**$2.57**	181,550	851,391	**$669,841**
SEEM Market	[8]	1,911	-	**-1,911**	$33.37	-	**NA**	63,773	-	**-$63,773**
Real-Time Market	[9]	385	3,392	**3,007**	$40.61	$36.34	**-$4.28**	15,632	123,272	**$107,640**
Total	[10]	**171,490**	**171,490**	**0**	**$12.49**	**$11.10**	**-$1.39**	2,141,618	1,902,751	**-$238,867**
% Change in APC	[11]									***-11.2%***

Adjusted Production Cost: Dominion

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	21,936	18,866	**-3,069**	$23.93	$19.58	**-$4.35**	524,809	369,339	**-$155,470**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	2,361	7,427	**5,066**	$41.35	$33.83	**-$7.51**	97,625	251,259	**$153,634**
SEEM Market	[4]	886	-	**-886**	$34.40	-	**NA**	30,478	-	**-$30,478**
Real-Time Market	[5]	1	94	**94**	$61.80	$36.28	**-$25.52**	34	3,415	**$3,381**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	6	226	**220**	$46.74	$39.00	**-$7.75**	266	8,799	**$8,533**
SEEM Market	[8]	99	-	**-99**	$42.92	-	**NA**	4,240	-	**-$4,240**
Real-Time Market	[9]	0	1,083	**1,083**	$67.57	$38.13	**-$29.43**	18	41,291	**$41,273**
Total	[10]	**25,078**	**25,078**	**0**	**$25.86**	**$22.89**	**-$2.97**	648,422	573,923	**-$74,499**
% Change in APC	[11]									***-11.5%***

Adjusted Production Cost: Santee Cooper

Cost Components	Row	GWh Status Quo	GWh Market	GWh Difference	$/MWh Status Quo	$/MWh Market	$/MWh Difference	Total ($1000s/Year) Status Quo	Total ($1000s/Year) Market	Total ($1000s/Year) Difference
Production	[1]	27,151	23,327	**-3,824**	$23.06	$19.87	**-$3.20**	626,202	463,411	**-$162,792**
Purchases	[2]									
Bilateral/Day-Ahead Market	[3]	1,486	6,417	**4,931**	$48.05	$33.60	**-$14.45**	71,416	215,623	**$144,207**
SEEM Market	[4]	317	-	**-317**	$41.00	-	**NA**	13,005	-	**-$13,005**
Real-Time Market	[5]	70	120	**50**	$55.92	$37.96	**-$17.96**	3,925	4,560	**$636**
Sales	[6]									
Bilateral/Day-Ahead Market	[7]	103	266	**163**	$33.97	$42.23	**$8.26**	3,512	11,255	**$7,743**
SEEM Market	[8]	217	-	**-217**	$33.29	-	**NA**	7,240	-	**-$7,240**
Real-Time Market	[9]	6	901	**894**	$34.88	$39.77	**$4.89**	226	35,820	**$35,594**
Total	[10]	**28,697**	**28,697**	**0**	**$24.52**	**$22.18**	**-$2.34**	703,570	636,520	**-$67,050**
% Change in APC	[11]									***-9.5%***

The Brattle Group: Offices

Brattle Group Practices and Industries

ENERGY & UTILITIES

- Competition & Market Manipulation
- Distributed Energy Resources
- Electric Transmission
- Electricity Market Modeling & Resource Planning
- Electrification & Growth Opportunities
- Energy Litigation
- Energy Storage
- Environmental Policy, Planning and Compliance
- Finance and Ratemaking
- Gas/Electric Coordination
- Market Design
- Natural Gas & Petroleum
- Nuclear
- Renewable & Alternative Energy

LITIGATION

- Accounting
- Analysis of Market Manipulation
- Antitrust/Competition
- Bankruptcy & Restructuring
- Big Data & Document Analytics
- Commercial Damages
- Environmental Litigation & Regulation
- Intellectual Property
- International Arbitration
- International Trade
- Labor & Employment
- Mergers & Acquisitions Litigation
- Product Liability
- Securities & Finance
- Tax Controversy & Transfer Pricing
- Valuation
- White Collar Investigations & Litigation

INDUSTRIES

- Electric Power
- Financial Institutions
- Infrastructure
- Natural Gas & Petroleum
- Pharmaceuticals & Medical Devices
- Telecommunications, Internet, and Media
- Transportation
- Water

Appendix D: Stakeholder Engagement Process

Our engagement with the Study Committee included the following:

- The Study Committee provided direction and approval of the study scope
- We provided educational workshops with the Study Committee on the implication of different market reform options
- Our team connected the Study Committee with practitioners in the industry to speak about their experience with market reforms.
- Our team served as an intermediary between the Study Committee and the Advisory Board; we collected written input from the Advisory Board and provided the Study Committee with a summary of that information. The Advisory Board members each had the opportunity to speak in front of the Study Committee.
- We provided the Study Committee with the Draft Report for review and comment.

Our engagement with the Advisory Board included the following:

- We conducted one-on-one interviews with each member of the Advisory Board to record their views on market reform and understand their hopes/priorities for the study.
- Brattle and several members of the Advisory Board (Duke, DESC, Santee Cooper, Central Elec Coop, and Piedmont Municipal Power Association (PMPA)) signed an NDA to share data from the signees with Brattle to inform our modeling effort.
- Our team conducted regular update meetings with the Advisory Board to discuss the market reform options we analyzed, our study approach and methodologies, the benefit and cost metrics analyzed, and potential draft recommendations.
- The Advisory Board was provided the draft results of the modeling effort and was given the opportunity to review draft results and provide comments.
- The Advisory Board was provided the Draft Report, including the recommendations on market reform options and was given the opportunity to review the draft and provide comments.
- Brattle responded to Advisory Board comments on the Draft Report in a live meeting and responded to all written comments in a separate document submitted to the Study Committee.

The full list of all meeting materials are available at the Electricity Market Reform Measures Study Committee website and a list of Study Committee and Advisory Board meetings is provided below.

Study Committee Meetings:

Presenter	Date
Study Committee	June 21, 2021
The Brattle Group	September 30, 2021
The Brattle Group	March 9, 2022
The Brattle Group	March 23, 2022
The Brattle Group	April 21, 2022
The Brattle Group	May 10, 2022
The Brattle Group	June 28, 2022
The Brattle Group, Advisory Board	July 13, 2022
Noel Black, VP Federal Regulatory Affairs, Southern Company	September 1, 2022
Commissioner Ted Thomas, Arkansas Public Service Commission	
Bruce Rew, SVP Operations, Southwest Power Pool	
The Brattle Group	

Advisory Board Meetings:

Presenter	Date
The Brattle Group	June 28, 2022
The Brattle Group	July 13, 2022
The Brattle Group	July 27, 2022
The Brattle Group	September 26, 2022
The Brattle Group	November 17, 2022
The Brattle Group	December 19, 2022
The Brattle Group	March 14, 2023

Listed in the order specified in Act 187, the members of the advisory board are:

Nanette S. Edwards	Executive Director	Office of Regulatory Staff
Patrick Cobb	Associate State Director at AARP	Federal Advocacy/Strategic Communications
Nelson Peeler	Senior Vice President and Chief Transmission Officer	Duke Energy
Marty Watson	Chief Power Supply Officer	Santee Cooper
Pandelis (Lee) Xanthakos	Director Electric Transmission	Dominion Energy
Sue Berkowitz Esq.	Director	SC Appleseed Justice League Center
Margaret Small	Head of Operations & Event Manager	SC Appleseed Justice League Center
Steve Chriss	Director, Energy Services	Walmart
Jennifer Burton	Senior Energy Manager	Lowe's Companies Inc.
Dennis Boyd	Electrical Power Engineer	Nucor Steel
Jamey Goldin	Energy Regulatory Counsel	Google
Eddy Moore	Energy Senior Program Director	Coastal Conservation League
Hamilton Davis	VP Markets and Regulatory Affairs	Southern Current LLC
Thomas L. Rhodes III	President	Rhodes Graduation Service
John Frick	VP Government Relations	The Electric Cooperatives of South Carolina Inc. (ECSC)
Jimmy Bagley	Deputy City Manager	Rockhill, SC
Joel Ledbetter	General Manager	Easley Combined Utilities
Stephen "Steve" Thomas	Senior Manager, Energy Contracts	Domtar
Amy Kurt	Director of Development, Eastern Region & Canada	EDP Renewables (EDPR)
Tyson Grinstead	Director of Public Policy	Sunrun
Mark Svrcek	Chief Operating Officer & Sr. VP of Corporate Strategy	Central Electric Power Cooperative Inc.
Bryan Stone	President	Lockhart Power Company
Neal Baxley	Owner	Baxley Farms, LLC