

# Unlocking the Value of SEEM

IDENTIFYING RECOMMENDATIONS TO INCREASE CUSTOMER SAVINGS ACROSS THE  
SOUTHEAST REGION

PREPARED BY

John Tsoukalis  
Peter Heller  
Kathleen Spees

PREPARED FOR

WRI US Polsky Energy Center

APRIL 2026



**Brattle**

---

## NOTICE

- This report was prepared for the WRI US Polsky Energy Center, in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts.
- The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.
- There are no third-party beneficiaries with respect to this report, and The Brattle Group does not accept any liability to any third party in respect of the contents of this report or any actions taken or decisions made as a consequence of the information set forth herein.

© 2026 The Brattle Group, Inc

---

TABLE OF CONTENTS

- Executive Summary ..... 1**
  
- I. Starting Point: How SEEM Works ..... 4**
  - A. Trading Platform Mechanics and Data ..... 4
  - B. Membership and Participation in SEEM..... 7
  - C. Regulatory History and Governance Arrangement..... 9
  
- II. Evaluating SEEM’s Performance ..... 12**
  - A. Projected Benefits During SEEM Formation..... 12
  - B. Data Transparency in SEEM..... 14
  - C. Realized Participation and Benefits Accrued ..... 15
  - D. Experience with SEEM: Interviews with Members, Participants, and Stakeholders ..... 22
  
- III. Benchmarking SEEM to Other Wholesale Power Markets ..... 24**
  - A. Market Design and Planning Elements Comparison ..... 25
  - B. Role of States in Market Governance..... 28
  - C. Delivered Benefits Comparison ..... 31
  
- IV. Case Study: Factors that Catalyzed Western US Market Evolution ..... 33**
  
- V. Recommendations for Increasing Customer Cost Savings..... 39**
  - A. Scope 1: Incremental Enhancements to Existing SEEM Platform ..... 41
  - B. Scope 2: Low-Cost Options for Regionally Optimized Markets ..... 43
  
- List of Acronyms ..... 44**

# Executive Summary

---

Since beginning operations in November 2022, the Southeast Energy Exchange Market (SEEM) has operated as an intra-hour, 15-minute bilateral trading platform that uses available non-firm transmission capacity at zero cost to facilitate additional energy transactions among participants. SEEM was designed to function as an enhanced short-term bilateral trading mechanism, meaning it does not involve centralized dispatch, unit commitment, or system-wide economic optimization. This report provides data on SEEM's performance after roughly three years of operation and presents options to increase customer cost savings through targeted enhancements to the platform and voluntary, low-cost regional market reforms. We reviewed public reports on market utilization and reported benefits to compare realized participation and benefits accrued to the expected benefits reported prior to market formation. Additionally, we interviewed stakeholders across the region, including utilities, current and former regulators, large power customers, independent power producers (IPPs), and developers, to understand each group's view of the market and to gain insight into potential changes that would increase customer savings in the region.

We find that although trading activity and economic benefits from SEEM are steadily increasing, realized performance remains materially below projections made during market formation. Average hourly cleared volumes are roughly 10% of forecast levels and cumulative benefits over the first three years—less than \$25 million, or approximately \$7 million annually—fall far short of the approximately \$40 million per year predicted over the same period prior to SEEM creation. SEEM transactions also represent only about 1% of total bilateral trade volumes in the Southeast. Benchmarking against more coordinated market constructs elsewhere in the US indicates that these limited benefit outcomes are largely a function of SEEM's structure. As an incremental enhancement to bilateral trading without regionally optimized dispatch, coordinated unit commitment, or transparent price formation, SEEM's design inherently limits the scale of achievable savings. Stakeholder perspectives reflect this. Many stakeholders characterize SEEM as functioning as intended and delivering low-cost incremental value while preserving local control. Regulators cite uneven transparency and limited visibility into state-specific benefits. Renewable energy developers and large customers report minimal impact on investment or procurement decisions due to the absence of actionable price signals and system visibility. Despite these differing views, there is broad agreement that SEEM should evolve in ways that meaningfully increase customer cost savings.

SEEM can achieve increased customer cost savings by expanding participation and trading volumes while reducing operational, reliability, and financial risks for customers. We present a set of recommendations under two "scopes" of potential enhancements to evolve regional market coordination—without transitioning to a Regional Transmission Organization (RTO). These options are designed to preserve local utility control over balancing, reliability, resource planning, and transmission planning and operation functions, as well as maintain state authority

over policy, resource adequacy, utility investment decisions, and retail rates. Our recommendations include incremental enhancements to the existing platform to improve transparency and utilization (Scope 1) and low-cost options for regionally optimized markets (Scope 2). All recommendations under Scope 2 are completely voluntary with relatively low exit costs. The details of these recommendations are summarized in Tables ES-1 and ES-2.

**TABLE ES-1. SCOPE 1: INCREMENTAL ENHANCEMENTS TO EXISTING SEEM PLATFORM**

<b>Increase Transparency and Expand Reporting</b>
<ul style="list-style-type: none"> <li>• Publish more detailed metrics on benefits (e.g., by participant and how utilities calculate their own benefits) and standardize utility-level reporting of SEEM operations and benefits</li> <li>• Provide detailed data on transactions, including counterparties for transactions and instances when physical congestion is the limiting factor for clearing economic trades</li> </ul>
<b>Create a Role for State Regulators in Governance</b>
<ul style="list-style-type: none"> <li>• Consider introducing a regional body of state regulators to oversee SEEM, provide guidance on changes to the market, and create a forum for stakeholders to engage</li> <li>• Increase the role of the market auditor to an independent market monitor focused on identifying efficiency opportunities</li> </ul>
<b>Expand Market Trading and Liquidity</b>
<p><b>Improving Interaction with Existing SEEM Platform</b></p> <ul style="list-style-type: none"> <li>• Encourage automated utility processes for determining dispatch of resources and the quantity of energy available for bidding/offering into SEEM to increase liquidity</li> <li>• Provide the opportunity for IPP-owned generation to sell curtailed energy in SEEM—<i>requires new contract structures between IPPs and utility off-takers</i></li> </ul> <p><b>Enhancements to SEEM Platform</b></p> <ul style="list-style-type: none"> <li>• Increase granularity of trading window (5- or 10-minute intervals)—<i>may require changes to e-Tag system</i></li> <li>• Expand the market to include hourly or multi-hour real-time and day-ahead transactions</li> <li>• Explore targeted operating reserve offerings</li> <li>• Test changes to market constraints (e.g., remove option to exclude specific counterparties in transactions) to determine how to relax some constraints to clear more transactions in the existing platform</li> </ul>

**TABLE ES-2. SCOPE 2: LOW-COST OPTIONS FOR REGIONALLY OPTIMIZED MARKETS**

<b>Establish an Energy Imbalance Market (EIM)</b>
<ul style="list-style-type: none"><li>• Implement regionally optimized dispatch on 5-minute basis, regional procurement of operating reserves, and sharing of unused transmission capacity in real-time to unlock significantly higher customer cost savings</li><li>• Design and operate the EIM at relatively low cost that would not require utilities to forfeit balance authority (BA), resource planning, or transmission planning functions (e.g., Western Energy Imbalance Market (WEIM) has saved customers nearly \$8 billion in past 11 years while only costing a few million to set up and operate)</li><li>• Create transparent nodal pricing signals, with sub-hourly prices posted shortly after market clearing</li></ul>
<b>Develop a Regional Resource Adequacy (RA) Program</b>
<ul style="list-style-type: none"><li>• Provide common accreditation for generation resources and a regional planning reserve margin to leverage diversity of peak load and variable resources across entire region</li><li>• Maintain states' authority to determine energy policy, approve utility investment decisions, establish rates for customers in their states, or to regulate utility operations and reliability functions</li></ul>
<b>Implement a Day-Ahead Market</b>
<ul style="list-style-type: none"><li>• Extend same functionality of an EIM to day-ahead unit commitment and dispatch, unlocking large customer cost savings and create transparent locational price signals for investors in the region</li><li>• Design and operate the market at relatively low cost that would not require utilities to forfeit BA, resource planning, or transmission planning functions</li></ul>

# I. Starting Point: How SEEM Works

---

The Southeast Energy Exchange Market (SEEM) is a voluntary, intra-hour energy trading platform launched in November 2022 by several Southeastern utilities. Designed to increase the volume of energy trading between utilities in the region, SEEM facilitates bilateral trades of non-firm economic energy across its member footprint. More specifically, SEEM provides a platform for near real-time energy exchange by matching willing buyers and willing sellers for 15-minute energy intervals, creating a new way to trade energy sub-hourly in addition to the traditional hourly, intra-day, day-ahead, and longer-term bilateral arrangements that have existed in the region for many years. SEEM is intended to operate as a supplement to the existing bilateral trading framework—not as a replacement or fundamental redesign of the Southeast’s existing traditional electricity market structure.

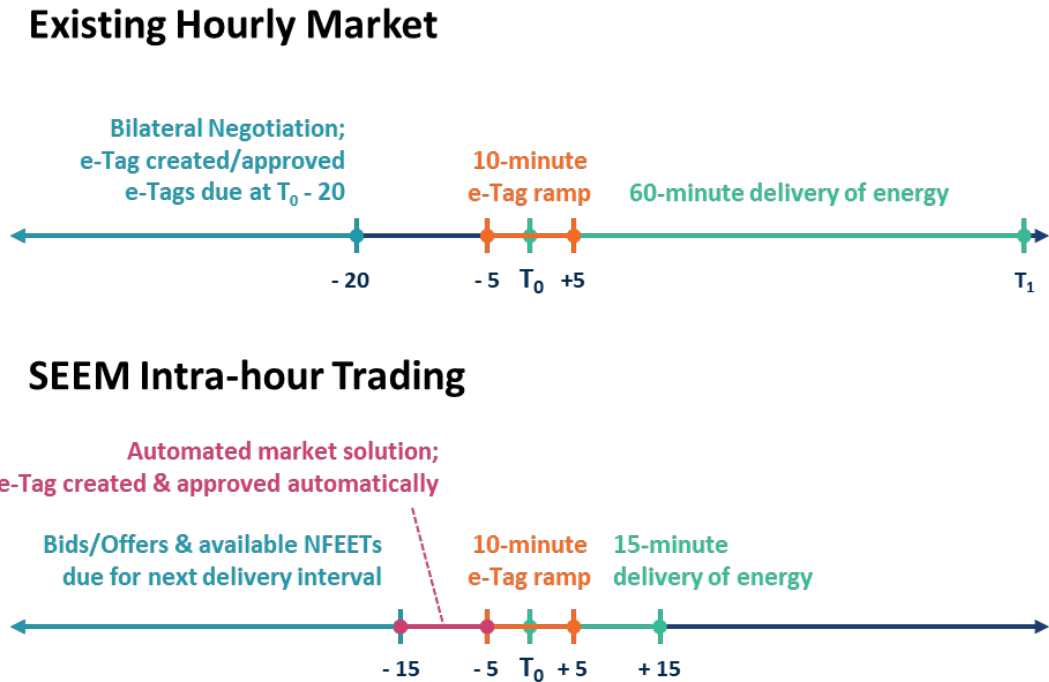
This section summarizes the trading platform mechanics, membership versus participation in SEEM, and its regulatory history and governance structure.

## A. Trading Platform Mechanics and Data

The SEEM platform provides a mechanism for participants across the Southeast to use available, unused transmission capacity to facilitate 15-minute bilateral trades near real time operations. In traditional bilateral energy trading markets, electricity is bought and sold through negotiated agreements between individual counterparties. Each trade is negotiated to specify the quantity of power, the delivery point, time interval (for how long power will be delivered), and the price. These bilateral trades range in duration from long-term agreements lasting months or years to short-term, hourly transactions arranged a day ahead or within the same operating day.

SEEM provides a standardized platform that automatically matches buy and sell offers every 15 minutes using available non-firm transmission capacity. Bids must be submitted at least 15 minutes in advance and are cleared every 15 minutes for each corresponding 15-minute delivery interval. Figure 1 illustrates the timing of the hourly bilateral market and the SEEM intra-hour market.

FIGURE 1. TIMING IN THE HOURLY AND INTRA-HOUR BILATERAL MARKET IN THE SOUTHEAST



Source: This figure is adapted from the figure in [Operations Affidavit](#), P 35, p. 13.

Unused transmission capacity is made available at no cost through the Non-Firm Energy Exchange Transmission Service (NFEETS). Essentially, when the platform determines a match, it automatically schedules the power flow using available non-firm transmission capacity across the member transmission providers’ systems. This design is intended to allow participants to complete transactions much closer to the time of delivery (at 15-minute intervals), improving system efficiency by enabling more flexible use of existing transmission and generation resources across the region. Importantly, SEEM is unlike certain other market structures in the US in that it does not have centralized dispatch or unit commitment, and does not offer additional products beyond 15-minute energy. SEEM’s 15-minute trading is designed for utilities to trade excess energy, which limits the volume of trading that takes place in the market relative to other market structures that exist across the US that conduct market-wide dispatch for all resource bid into the market across the footprint. The comparison of SEEM to other market structures is explored in later sections of this report.

When a participant wants to buy or sell energy through SEEM, the process begins with a bid or offer submission. Participants can either submit an offer to sell a specific block of non-firm energy or a bid to buy energy. The submission deadline is 15 minutes before the start of the upcoming delivery interval, after which no modifications on offers/bids are allowed. There are several key data points that every bid or offer must have in the platform:<sup>1</sup>

<sup>1</sup> [SEEM Business Practices Manual](#), Section 3.3 (Participant Inputs).

- **Trade Volume.** Bids and offers must both be in increments of 4 megawatts (MW). The minimum trade that can occur is for 4 MW over one 15-minute interval.
- **All or Nothing Selection.** This selection provides buyers and sellers with the option to allow their trade volume submitted to be matched at any volume equal or below their offer, including multiple trades to fulfill the full volume, subject to the 4 MW increment constraint.
- **Bid/Offer Price.** The submitted bid price represents the maximum price (\$/megawatt hour, MWh) that the buyer is willing to pay, and the submitted offer price represents the minimum price (\$/MWh) that the seller is willing to accept. There is no requirement that prices be at cost or cost-based, and voluntary participants can price their bids/offers to reflect market value, opportunity cost, or any other considerations set by the entity.
- **Source or Sink Location.** Both the source and the sink location must be registered and tied to a specific generator or load (or system) where the energy is generated or consumed, respectively.
- **Specific Delivery Interval.** All bids and offers can be submitted from seven days up to 15 minutes prior to the delivery interval. The specific delivery interval must be selected, and the bids and offers can be modified until the 15-minute window prior to delivery.

Offers for energy allow participants to include a maximum price that they are willing to accept as an optional input to avoid selling power above any regulatory or internal limits. After all offers and bids are received for a specific delivery window, the SEEM system runs an automated algorithm to match compatible bid-offer pairs. For a match to be compatible, the bid (buyer's willingness to pay) must be greater than the offer (seller's willingness to accept) minus any losses between the source and the sink. While the NFEETS provides for zero-cost transmission service, the costs of transmission losses are accounted for. Transmission losses are determined by each of the participating transmission providers using a loss factor (percent) and loss rate (\$/MWh). If a trade passes through multiple participating transmission providers, all the financial loss data must be utilized in determining if the trade should clear. The seller is responsible for all financial losses to deliver the energy to the border of the buyer's balancing authority (BA).

SEEM operates as a split-the-savings platform in which the transaction price is the midpoint of the bid and offer prices minus half of the net losses so that the buyer and the seller evenly split the cost savings between individually matched counterparties. The platform is automated to find the matching of economic offers and bids that maximizes the total SEEM benefit across the region for the delivery period while honoring system requirements and constraints.

At present, SEEM provides the following public data:<sup>2</sup>

- **Monthly informational reports**, published by the fifth day of the following month, which provide the total volume of bids and offers, number of trades, total volume cleared, minimum/maximum/average trade prices, and estimated market benefits.

---

<sup>2</sup> Note that this information is only made available to individuals or entities that register for access (subject to approval by SEEM) on the SEEM website: <https://southeastenergymarket.com/my-account/>.

- **Daily information reports**, published by 6:00 AM the following day, which provide hourly data on volume of bids and offers, number of trades, total volume cleared, and average price.
- **Hourly information reports**, published 15 minutes after the hour, that provide data on the volume of bids and offers, numbers of trades, and total volume cleared. Note that the hourly reports do not currently include average prices; however, based on a November 2025 settlement agreement between SEEM and a coalition of Southeastern environmental groups, SEEM will post the average price data for transactions every hour.<sup>3</sup>
- **Monthly Available Transfer Capability (ATC) usage**, including 15-minute interval data on the ATC available, used, and unused for each participating transmission provider.
- **Monthly bid and offer details**, including all volumes, prices, and delivery intervals for all bids and offers received (no participant identifying information is reported).
- **Monthly bid and match details**, including information on the bids and offers that received a match (no participant identifying information or volume of trade cleared is reported).

These reports show total volumes traded and benefits, calculated as the bid-ask spread less losses, but do not disclose which participants traded, at what times, or what the clearing price was for each transaction or each trading interval, and no individual trade-level data is made available to the public.

## B. Membership and Participation in SEEM

Entities can be a part of SEEM as either a member or a participant. Members are those that have signed the SEEM Agreement and therefore have formal governance rights within the market. Eligibility for membership is limited to load-serving entities and certain related organizations located within the SEEM territory, defined as “the areas served by the Participating Transmission Providers.”<sup>4</sup> Specifically, eligible members must be one of the following:<sup>5</sup>

- A load-serving entity located within the territory.
- An association, cooperative, or governmental entity that is a load-serving entity located in the territory.
- An association, cooperative, or governmental utility created for the purpose of providing energy to cooperative or governmental load-serving entities located in the territory (includes disaggregated cooperatives that are not affiliated, but have responsibilities related to the same load).

---

<sup>3</sup> See the November 7, 2025 settlement agreement filed with the FERC under [ER26-445](#).

<sup>4</sup> See [Southeast Energy Market Exchange Agreement](#) (SEEM Agreement), December 28, 2020, submitted as Attachment A to the [Southeast Energy Exchange Market Proposal Transmittal Letter](#) (Transmittal Letter)

<sup>5</sup> [Affidavit of Christopher McGeeney and Corey Sellers](#) (Operations Affidavit), Attachment C to the Transmittal Letter, P 15, p. 5.

New members can enroll in the year prior to that in which they would like to start participating in the market. Members that are also participating transmission providers must provide NFEETS (i.e., zero-cost non-firm transmission service for transactions via the SEEM platform). Members pay an allocation of all SEEM legal, software, audit, and operation expenses, but they receive a seat on the SEEM Membership Board that governs the market and its operations, discussed in the next section.

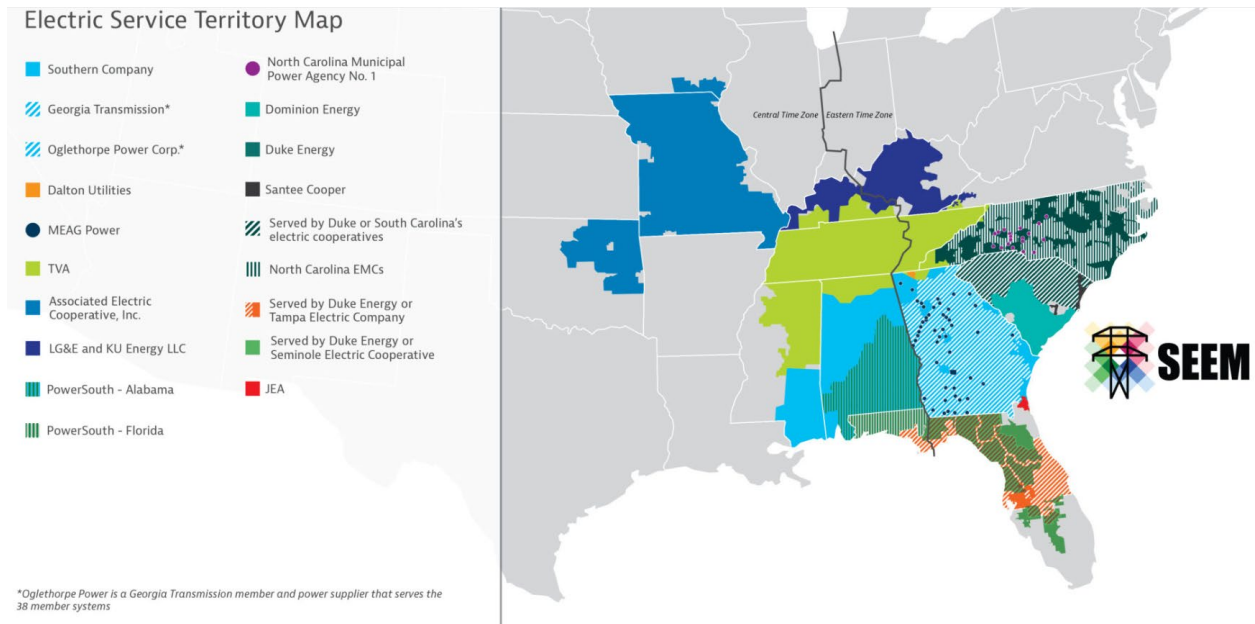
In contrast to SEEM members, SEEM participants comprise a more diverse set of possible entities. All SEEM members are participants, but not all participants are necessarily members as not all entities that are eligible to be participants are eligible to become members. SEEM participation is broader in scope and is open to entities that meet specified technical and operational criteria. To qualify as a participant in SEEM, an entity must meet all the following criteria:

- Own or otherwise control a source and/or be contractually obligated to serve a sink within the territory.
- Be connected to a participating transmission provider and have executed NFEETS Agreements with each provider—in its Order on Remand in March 2025, the Federal Energy Regulatory Commission (FERC, or the Commission) determined that the SEEM Agreement must be revised to include provisions to allow for participation via pseudo-tie, discussed in the next section.
- Be able to generate or consume a minimum of 4 MW, which is the minimum bid size.
- Have or enter into an enabling agreement with at least three or more participants, which sets the terms for future wholesale power purchases and sales between parties.

By these rules, participation in the market is open to entities with generation or load that are permitted to participate in wholesale bilateral markets (i.e., non-utility entities), including IPPs. However, there has been no direct participation (i.e., submission of bids or offers directly) by IPPs during the first three years of market operations. In some cases, IPPs' resources may be part of a utility's offer into the market, but that is done by the utility as the participant instead of directly by the IPP. Registration as a participant can occur at any time and is free.

SEEM has grown since its launch in 2022, most notably when several utilities in Florida joined in 2023, and there are currently 24 members and participants across 12 Southeastern states, as shown in Figure 2 below.

**FIGURE 2. SEEM FOOTPRINT (AS OF MARCH 2026)**

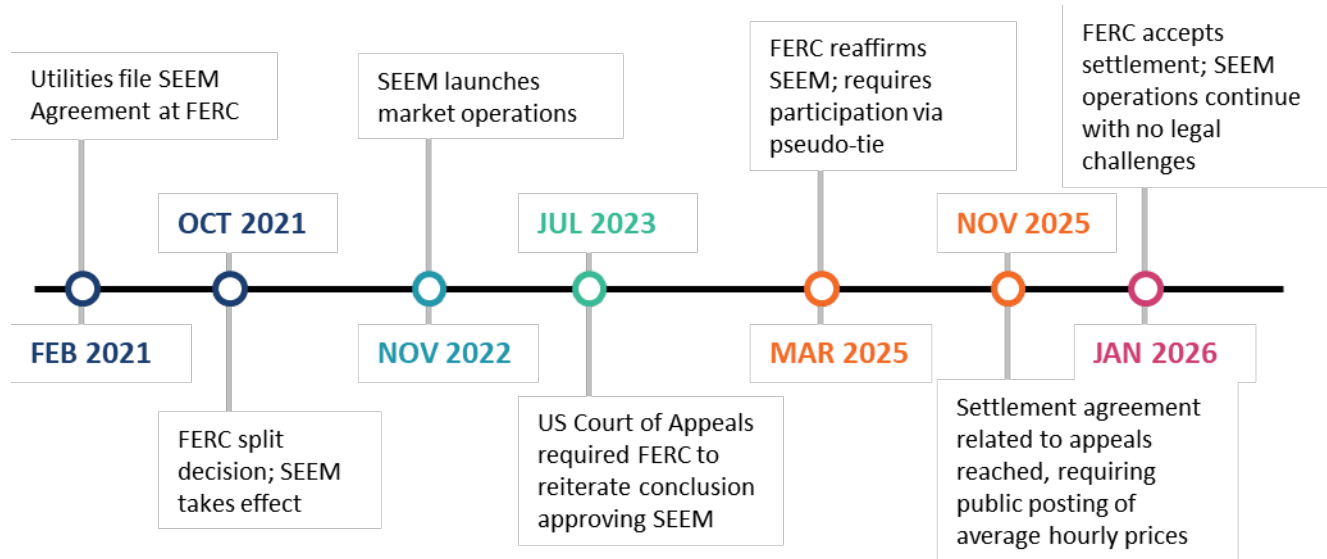


Source: SEEM, [Southeast Energy Exchange Market](#).

## C. Regulatory History and Governance Arrangement

SEEM’s development has followed a multi-year path shaped by regulatory review and legal challenges by stakeholders in the region. Figure 3 summarizes the key milestones in SEEM’s formation, approval, litigation, and subsequent revisions. The discussion below provides additional detail on its regulatory history and governance arrangement.

FIGURE 3. TIMELINE OF SEEM'S REGULATORY AND LEGAL HISTORY



SEEM was proposed in a filing with FERC in February 2021 by a group of 14 utilities (herein referred to as the SEEM Proposal), with additional reference to several potential members.<sup>6</sup> The proposed market was described as an “extension and enhancement to the existing bilateral market” that was intended to reduce administrative burden and take advantage of unused transmission capacity to enable bilateral transactions in the near real-time operations of the grid.<sup>7</sup> In order to take advantage of unused transmission capacity, the SEEM Proposal included revisions to each member’s open-access transmission tariffs to create a NFEETS, which allowed for zero-cost transmission service for transactions via the SEEM platform. FERC was split in its decision (2–2) to approve or deny the SEEM Proposal, and the filings took effect by operation of law on October 12, 2021.<sup>8</sup> The concern among the opposing commissioners centered on SEEM’s structure limiting access to approved participants and adherence to rules that are controlled only by incumbent members.<sup>9</sup> After the SEEM filings took effect in October 2021, SEEM commenced operations on November 9, 2022.

<sup>6</sup> See [Southeast Energy Market Exchange Agreement](#) (SEEM Agreement), December 28, 2020, submitted as Attachment A to the [Southeast Energy Exchange Market Proposal Transmittal Letter](#) (Transmittal Letter) submitted to FERC on February 12, 2021.

<sup>7</sup> [Operations Affidavit](#), ¶ 9, p. 3.

<sup>8</sup> According to [Section 205\(g\) of the Federal Power Act](#), when FERC commissioners are tied in a 2–2 vote on the lawfulness of a change, the change automatically takes effect by default due to the failure to issue an order accepting or denying the change.

<sup>9</sup> See FERC, [Commissioner Clements’ Fair Rates Act Statement on Southeast EEM \(SEEM\)](#), Docket ER21-1111-002, October 20, 2021. Specifically, Commissioner Clements stated, “The transmission product and matching service are accessible only to Southeast EEM market Participants that sign and obtain countersigned participation agreements and acquiesce to the platform’s governing rules, which are controlled by a coterie of preferred Members. None of these characteristics are features of a bilateral market.”

Following the start of operations, several organizations challenged FERC’s split decision at the US Court of Appeals for the DC Circuit. In July 2023, the Court reviewed FERC’s earlier actions and found that FERC’s approval was “inconsistent” with its open access transmission precedent that requires transmission providers to offer non-discriminatory transmission service.<sup>10</sup> The court’s decision reflected concern that SEEM’s shared transmission service and participant restrictions could allow preferential treatment for member utilities. Specifically, the Court relied on the fact that NFEETS is “non-pancaked and therefore discounted,”<sup>11</sup> and required FERC to reiterate its conclusion that SEEM is not a loose power pool. On remand, however, FERC reopened the proceeding and issued a unanimous order reaffirming its acceptance of SEEM’s structure in March 2025. The Commission concluded that SEEM does not constitute a loose power pool and that its design is consistent with the *pro forma* Open Access Transmission Tariff.<sup>12</sup> The order directed participating utilities to make some changes to enhance transparency and ensure broader access—namely, the Commission required that SEEM allow eligible participation in the market via pseudo-tie.<sup>13</sup>

After continued legal and regulatory arguments regarding SEEM’s approval and operations, SEEM members and a coalition of stakeholders reached a unanimous settlement agreement in November 2025 to resolve outstanding litigation. After FERC reaffirmed SEEM, stakeholders continued to raise concerns that limited public data hindered the evaluation of SEEM’s performance. Under the settlement, SEEM members agreed to change the market rules to require that they will publish the weighted average match price as part of their hourly information reports.<sup>14</sup> In exchange, stakeholders agreed to withdraw legal challenges, allowing SEEM to continue operating. FERC approved the settlement in January 2026.

As described in its initial FERC filing, SEEM is governed only by its members. Decision-making authority is centralized in the Membership Board, comprised of one representative from each participating member entity, which oversees rules, policies, and standards. This board controls market rule-making and operational decisions, allowing the members to oversee their own market and activities. It also has the Operating Committee that manages day-to-day operations, which is staffed by four members. Each representative on the Membership Board has two types of votes. The first is a single vote that is used to determine the simple majority of voting members, referred to as the “Popular Vote.” The second is a weighted vote that is based on that member’s

---

<sup>10</sup> See [Advanced Energy United, Inc.](#), 82 F. 4<sup>th</sup> 1095.

<sup>11</sup> *Ibid.*

<sup>12</sup> FERC Order on Remand and Addressing Rehearing Requests, 190 FERC ¶ 61,151, March 14, 2025, P 1, p. 2. Note that if FERC had found that SEEM was a loose power pool, then the transmission owners would be required to provide transmission service through a joint pool-wide tariff that would make the zero-cost transmission service available to any interested market participant.

<sup>13</sup> A pseudo-tie is a scheduling agreement in which a generator or load located in one balancing authority area (BAA) is treated operationally as if it were in another BAA, allowing its output or demand to be balanced in real time by the balancing authority into which it is tied without it being physically located in that area.

<sup>14</sup> See Article 1 (“Hourly Posting of Price Information”) of the Petition for Approval of Uncontested Settlement Agreement and Request for Expedited Consideration filed on behalf of Alabama Power Company and the Southeast Energy Exchange Market Members under [Docket ER26-445](#) (November 7, 2025).

net energy for load relative to the total net energy for load of all members, known as the “Net Energy for Load (NEL) Vote.” For critical issues (e.g., SEEM Agreement amendments), the motion or action must have a majority of the Popular Vote and a *supermajority* of the NEL Vote.<sup>15</sup> The purpose of the NEL Vote is to ensure that higher paying members have higher voting rights.

SEEM stands apart from other regional market structures in the US in that it lacks independent board members and does not provide a formal governance role for regulators or external stakeholders, as discussed in Section III.B. However, there are two third-party entities that manage operations of the SEEM platform (SEEM Administrator) and monitor the functioning of the market (Independent Market Auditor), Hartigen and Potomac Economics, respectively.<sup>16</sup> The Independent Market Auditor continuously audits SEEM’s operations to ensure that the market is functioning in accordance with the market rules.<sup>17</sup> The auditor can publish its findings without prior approval from the SEEM members and can respond to inquiries from regulators about SEEM’s operations.<sup>18</sup> Additionally, FERC provides regulatory oversight since SEEM remains a FERC-jurisdictional market for wholesale power.

## II. Evaluating SEEM’s Performance

---

Drawing on three years of operating experience, this section reviews SEEM’s performance to date and summarizes the view of market members, participants, and regional stakeholders based on interviews we conducted with 11 different stakeholders in the region. It first recalls the expectations set during SEEM’s formation, then reviews actual activity and benefits realized to date, and finally discusses the experience of various participants and stakeholders in the market. We conducted interviews with utilities, regulators (former and current), IPPs and developers, and large power customers to inform the discussion on SEEM’s performance.

### A. Projected Benefits During SEEM Formation

When SEEM was proposed in February 2021, its member utilities based its formation on several key benefits that they expected the platform to deliver. By allowing for trades using ATC that would otherwise go unused, SEEM’s founding members asserted that it would provide increased

---

<sup>15</sup> [Operations Affidavit](#), ¶ 23, p. 7.

<sup>16</sup> See Potomac Economics, “[Monthly Audit Report on the Southeast Energy Exchange Market For May 2025](#),” June 30, 2025.

<sup>17</sup> [Operations Affidavit](#), ¶ 52, p. 20.

<sup>18</sup> [SEEM Agreement](#), Section 10.2.3. [Southeast EEM Market Rules](#), Section VI.D.6.

efficiency and lower customer costs across the region.<sup>19</sup> Specifically, the platform was expected to provide:

- **Significant Customer Cost Savings.** The SEEM Proposal cites an independent analysis that claims to have “conservatively estimated”<sup>20</sup> the benefit of SEEM would be between \$40–\$60 million (2020\$) annually in gross benefits through 2037 using baseline integrated resource plans.<sup>21</sup> In the highest case, when expectations included potential carbon constraints that increased renewables on the system, gross benefits were expected to exceed \$120 million (2020\$) annually by 2037. These benefits were expected to offset annual costs of around \$4 million (2020\$).<sup>22</sup>
- **Renewable Integration and Reduced Curtailment.** The SEEM Proposal stated that SEEM would “allow for better integration of diverse generation resources, including rapidly growing renewables, and is expected to reduce renewable curtailments.”<sup>23</sup> Because the platform enables transactions in the near real-time and spans across a large geographic footprint, it could enable the transfer of energy from areas with surplus renewable generation to areas looking to purchase cheaper generation, thereby avoiding curtailment of renewables. Greater diversity and flexibility to trade within the region was expected to translate into improved balancing of supply and demand in an increasingly renewable system.
- **Maintaining Autonomy and Avoided Bureaucracy.** As a result of the additionality of SEEM to the existing bilateral market, SEEM claimed that the benefits could be achieved at low cost and realized in the near term.<sup>24</sup> The core principles that were outlined by SEEM’s founding members included both that “[b]ureaucracy is minimized while benefits to customers are maximized” and each electric service provider, transmission provider, and BA maintained its independence.<sup>25</sup>

From the outset, many stakeholders in the region were skeptical of the benefits that SEEM’s proposal claimed the market would provide. The expected benefits set the bar high for SEEM, as it was expected to deliver tens of millions of dollars in customer savings per year, environmental benefits in the form of reduced curtailments, and increased system efficiency through better regional cooperation. Consumer advocates, clean energy groups, and some industrial customer groups intervened in the FERC proceeding to assert that SEEM’s design was too restrictive and questioned the plausibility of the purported cost savings. The Clean Energy Coalition claimed that

---

<sup>19</sup> [Transmittal Letter](#), p. 4.

<sup>20</sup> [Transmittal Letter](#), p. 11

<sup>21</sup> Benefits Analysis by Guidehouse Inc. and CRA International ([Guidehouse Report](#)), Attachment E-1 to the Transmittal Letter, p. 7.

<sup>22</sup> Transmittal Letter, p. 11. Internal company start-up and ongoing costs were calculated at \$3.1 million (2020\$) annually when levelized over a 20-year period, and vendor price estimates to operate and maintain the platform were estimated at less than \$1 million per year.

<sup>23</sup> [Affidavit of Aaron Melda and Lonnie Bellar](#) (Overview Affidavit), Attachment B to the Transmittal Letter, ¶ 26.

<sup>24</sup> *Ibid.*

<sup>25</sup> Transmittal Letter, p. 8.

the projected benefits were “likely overstate[d] and should be put in perspective.”<sup>26</sup> Intervenor were skeptical of the amount of market liquidity and corresponding economic benefit that the market would realize, in some cases citing to the benefits analysis that acknowledged that the most important risk to the market’s benefits is low member participation.<sup>27</sup>

## B. Data Transparency in SEEM

Data transparency has been a central issue in stakeholder discussions regarding SEEM, including in regulatory proceedings and related legal actions. Several stakeholders have argued that the ability to evaluate SEEM’s performance is constrained by the limited amount of transaction-level and participant-level data that is publicly available. While SEEM publishes certain high-level information about market operations, the public reports discussed previously do not provide disaggregated data on market transactions, participant behavior, or the distribution of economic benefit by member/participant.

As argued by stakeholders in the region, the data provided by SEEM is not adequate to calculate how benefits and participation are distributed across the region. For example, stakeholders cannot determine whether some utilities are consistently acting as sellers while others are primarily buyers, or whether the market is delivering value relatively evenly across all members or if benefits are concentrated among a few members. Therefore, an assessment of each utility’s net benefit (benefits less cost of operating in the market) is not possible based on the data provided by SEEM. The absence of transparent market data makes it particularly challenging for stakeholders in the region to evaluate and comment on the platform’s effectiveness and assess whether the platform is delivering cost savings above costs to operate SEEM for each member’s customers or whether cost savings are concentrated with a few members. In later sections, we discuss what information other markets around the US make publicly available and the upsides to doing so.

At the same time, discussions with SEEM members indicate that more detailed information is available within the SEEM market and is provided to member utilities. SEEM members and participants do receive the breakdown of economic benefit attributable to their participation and are disaggregated by individual members. These statements help utilities to evaluate their participation and assess the value of SEEM transactions relative to the counterfactual bilateral market and their costs. However, the content and format of these benefit reports are not universally made public. Additionally, we learned that there are some utilities that calculate their own internal benefit, as they claimed that the market-calculated benefit (bid-offer spread times volume delivered) does not fully capture the true market benefit. For example, some utilities might include avoided costs of operating additional units using internal model simulations that reflect economic benefits not captured in the bid-offer spread. The only public data, though, does

---

<sup>26</sup> [Comments of Advanced Energy Economy, Advanced Energy Buyers Group, Renewable Energy Buyers Alliance, and the Solar Energy Industry Association](#) in Docket No. ER21-1111, filed March 15, 2021, p. 27.

<sup>27</sup> Guidehouse Report, p. 8.

not show these additional benefits that the utilities claim to realize, so regulators and stakeholders are unable to confirm them. Some SEEM members file information with their regulators, such as the Mississippi Commission’s requirement for semi-annual reports, Duke’s reporting of their calculated benefits to their regulators in South Carolina and North Carolina, and the Georgia Commission’s review of SEEM data in rate cases—though there has not been a rate case in Georgia since SEEM’s inception in 2022. Therefore, public access to the information on the distribution of benefits between SEEM members remains mostly restricted. As mentioned previously, state regulators can request information about SEEM either from the utilities that they regulate or directly from the Independent Market Auditor at any time.

Policy makers and external stakeholders must then use only the publicly available data to monitor SEEM’s progress, including the auditor reports and any public information filed with state commissions. In the next section, we discuss SEEM’s realized participation and benefits accrued using the publicly available data through SEEM’s Public Data.<sup>28</sup>

## C. Realized Participation and Benefits Accrued

Data from SEEM’s actual operations from late 2022 through today allows us to compare actual trading activity and customer benefits against the initial projections. The SEEM platform appears to be running smoothly, and monthly trading volumes are steadily increasing as the market matures. However, the evidence so far suggests that the platform’s utilization and benefits have been significantly less than initially estimated by the independent studies of the market conducted prior to the market’s formation.

### MARKET UTILIZATION AND TRADE VOLUMES

The SEEM platform has been functional and operationally sound, with members reporting that interactions with the software have been positive. It appears to be functioning as intended, meaning that it provided an enhancement to the existing bilateral market for economic energy by creating the ability to trade intra-hour economic energy in the market and by pooling the use of available transmission for those transactions. The expansion of the market to include Florida utilities broadened the pool of participants and has increased trading activity. Trades in the calendar year 2025 average approximately 107,000 MWh per month, with an all-time high trading volume of over 130,000 MWh in May 2025, compared to an average of 51,000 MWh in its first year of operations.<sup>29</sup> According to SEEM’s monthly public informational reports from November 2022 through December 2025, the market has accrued around \$22 million in cumulative benefits, or about \$7.1 million per year on average.<sup>30</sup> Figure 4 below illustrates the growing participation and cumulative benefits the market has accrued for the region.

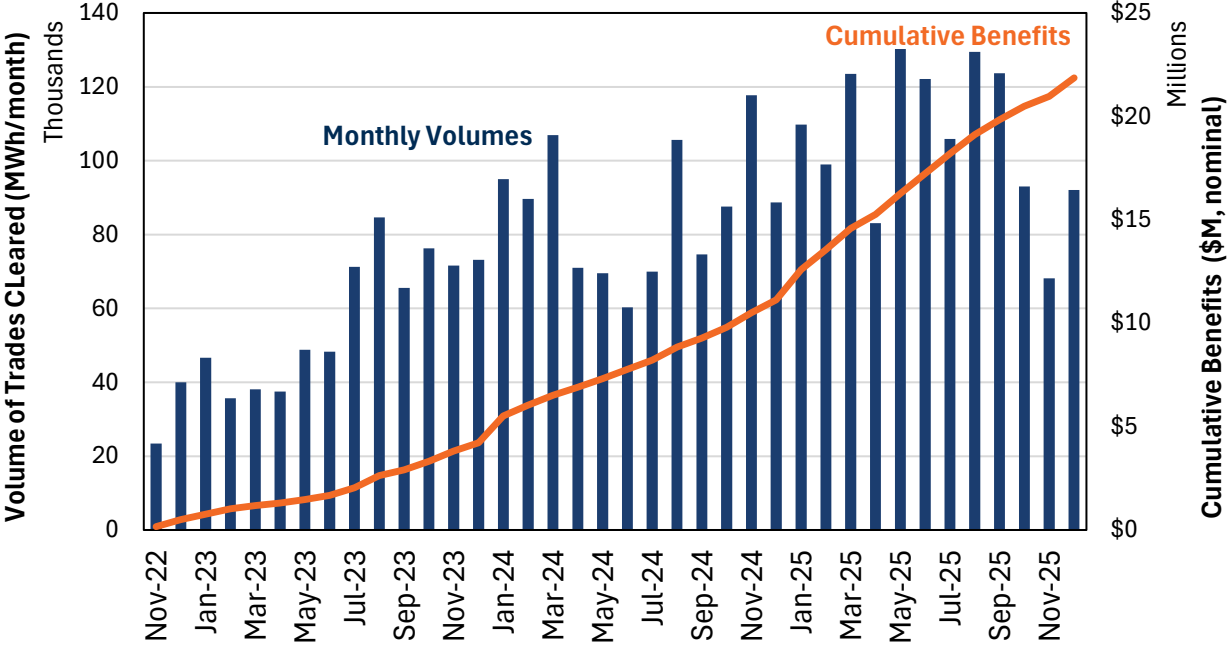
---

<sup>28</sup> [SEEM Public Data](#). Note that this link requires the user to create a login and request access from SEEM.

<sup>29</sup> [SEEM Public Monthly Information Reports](#), November 2022 through December 2025.

<sup>30</sup> *Ibid.*

FIGURE 4. MONTHLY VOLUME OF CLEARED ENERGY EXCHANGES AND CUMULATIVE MARKET BENEFITS



Source: SEEM Monthly Public Information Reports, November 2022 through December 2025.

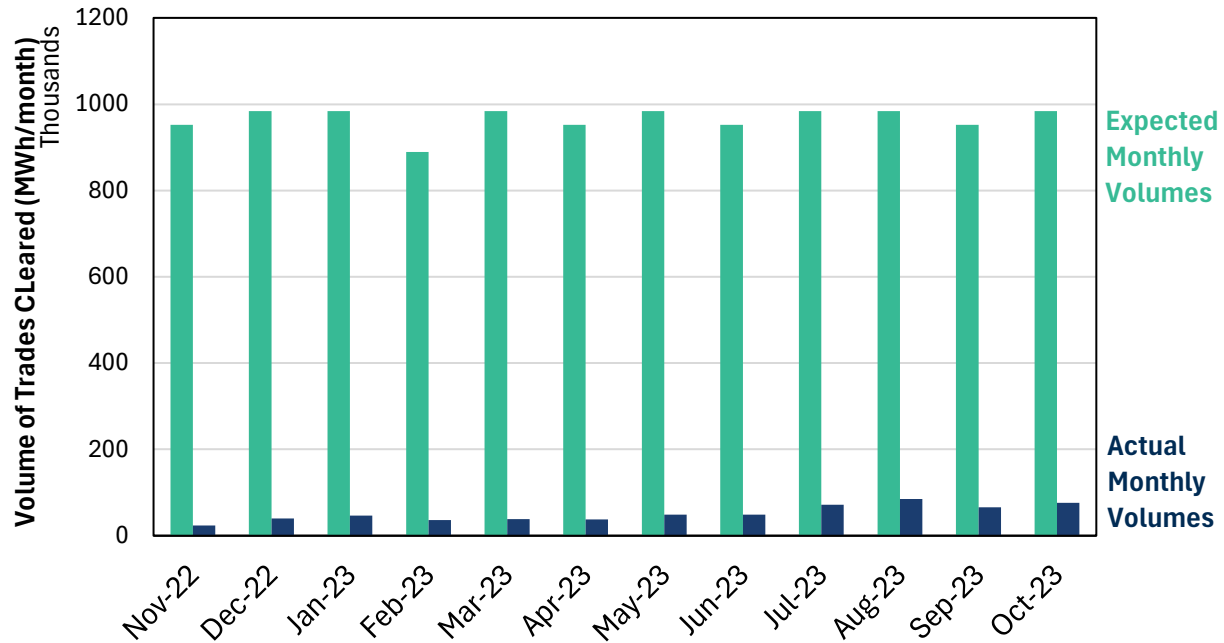
From a market participation perspective, SEEM members are trading much less energy than predicted. In the SEEM Proposal, the independent analysis estimated that there would be an average hourly trade volume of 1,323 MWh in the first year of operations (assumed to be the calendar year 2022 in the study).<sup>31</sup> During SEEM’s actual first year of operations (November 2022 through October 2023), average hourly trading volumes were just over 70 MWh.<sup>32</sup> This level represents roughly 5% of the initially forecasted trading activity, suggesting that the market’s early adoption and early liquidity has been much less and increasing more slowly than anticipated. Figure 5 illustrates the gap between expected trade volumes in the first year of market operations and the actual volumes cleared in the market. The average hourly trading volumes in the most recent calendar year (2025) were around 150 MWh.<sup>33</sup> Therefore, in the most recent calendar year, the average hourly volume is about 11% of the initially forecasted volumes, even when accounting for Florida utilities that were not included in the SEEM footprint in the initial study.

<sup>31</sup> Guidehouse Report, p. 17.

<sup>32</sup> The total reported volume of trades between November 2022 and October 2023 is 616,398 MWh. Taking this total volume divided by the hours in the year (8760), the average hourly trade volume is 70.4 MWh/hr.

<sup>33</sup> The total reported volume of trades between January 2025 and December 2025 is 1,280,049 MWh. This volume divided by 8760 hours gives the average hourly trade volume of 146.1 MWh/hr.

FIGURE 5. EXPECTED VS. ACTUAL MONTHLY VOLUMES IN SEEM’S FIRST YEAR OF OPERATIONS



Sources and Notes: Actual monthly volumes are pulled from SEEM Monthly Public Information Reports, November 2022 through October 2023 (i.e., the first full year of market operations). Expected monthly volumes are derived using the expected average hourly trade volumes of 1,323 MWh multiplied by the number of hours in each month from November 2022 to October 2023.

The low volume of cleared transactions compared to expectations highlights the most important risk that was noted when determining the potential market value: limited liquidity.<sup>34</sup> Figure 6 presents the market auditor’s evaluation of the bids and offers for the month of November 2025. There are up to hundreds of thousands of MWh of bids and offers that were within the cleared bid-offer spread (i.e., lowest cleared offer to the highest cleared bid) but were not cleared in the market, as shown by the light green bars in Figure 6.<sup>35</sup> While some trades did not clear because transmission losses would have made them uneconomic,<sup>36</sup> there are a significant number of trades that did not clear likely as a result of “transmission constraints or participant constraints.”<sup>37</sup> Potomac Economics studies the ATC across the region during each monthly audit report, and they determined that “transmission was generally available to facilitate economic transactions in the SEEM region,” finding that the percentage of transmission-constrained segment intervals (meaning that ATC was not sufficient to clear SEEM transactions) was only 11%.<sup>38</sup> For participant constraints, the SEEM market rules describe a few constraints that can

<sup>34</sup> Guidehouse Report, p. 19 (“The study assumes a well-functioning, and relatively high-participation market. Limited participation by members is the largest risk to Southeast EEM benefits.”).

<sup>35</sup> Potomac Economics, “[Monthly Audit Report on the Southeast Energy Exchange Market for November 2025](#),” December 27, 2025, p. 8.

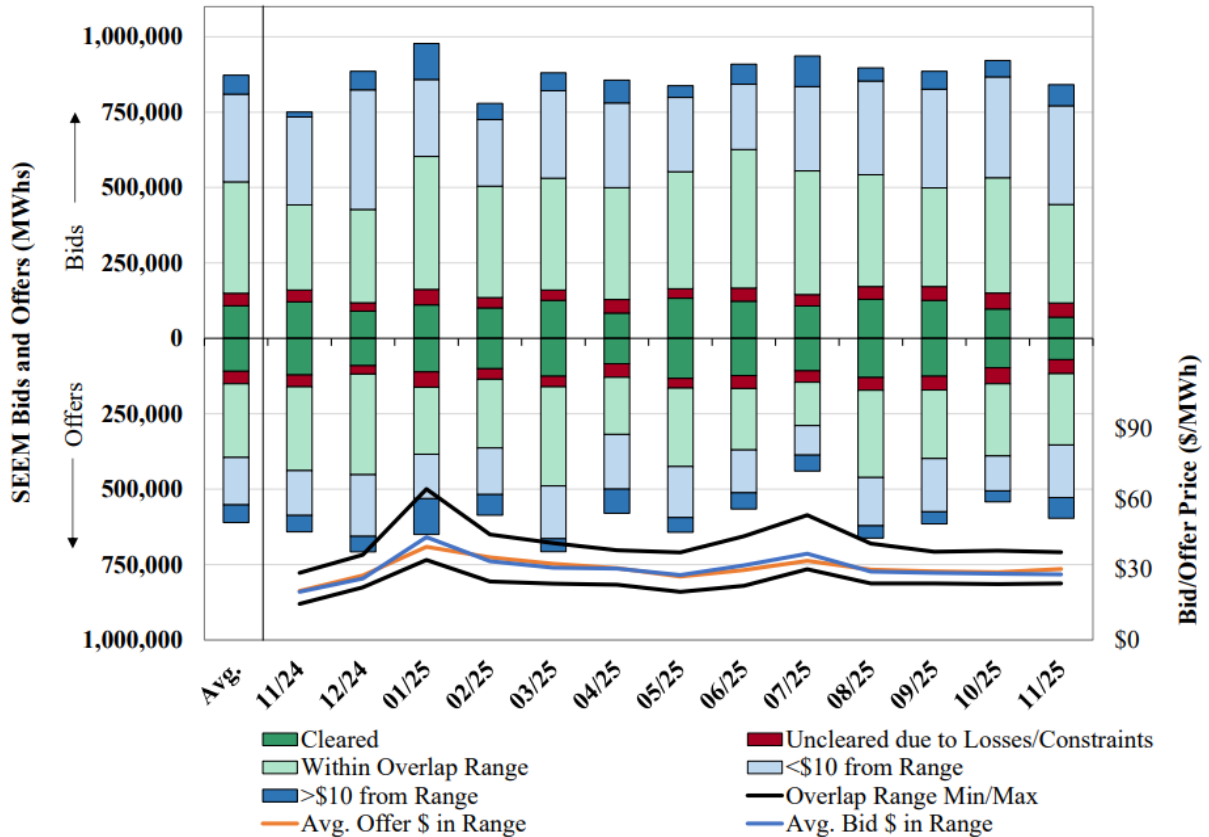
<sup>36</sup> For more information on how transmission losses are calculated, see the [SEEM Business Practices Manual](#), Section 3.4.2 (Loss Rate (\$/MWh) and Loss Factor (%)).

<sup>37</sup> *Id.*, p. 11.

<sup>38</sup> *Id.*, p. 18.

cause matches to not occur: (1) lack of an enabling agreement with a participant; (2) counterparty issues (e.g., credit risk); (3) affiliates restrictions; or (4) geographic issues causing supply or delivery point restrictions and related regulatory requirements.<sup>39</sup> In the Operations Affidavit filed at FERC, the members also cite the example that “if a Participant has toggled off another Participant, the algorithm will not consider their Bids and Offers as potential matches.”<sup>40</sup>

FIGURE 6. BID AND OFFER EVALUATION (MARKET AUDITOR REPORT, NOVEMBER 2025)



Source: Figure is duplicated from Potomac Economics, “[Monthly Audit Report on the Southeast Energy Exchange Market for November 2025](#),” December 27, 2025, Figure 3 (“Bid and Offer Evaluation”), p. 9.

It is unclear exactly what caused these economic trades to not clear the market (captured in the light green bars above); however, it appears that additional economic benefit for customers in the region could be unlocked by enabling additional economic trade. An analysis that diagnoses the causes of these trades not clearing and that understands what market optimization changes might enable additional trade to occur should be considered.

<sup>39</sup> [SEEM Market Rules](#), p. 6.

<sup>40</sup> [Operations Affidavit](#), ¶ 45, p. 18.

## COMPARISON TO REGION-WIDE BILATERAL TRADING

To put the volumes that are traded in SEEM into perspective, we compared the volumes of energy exchanged in SEEM to the other bilateral transactions executed across the footprint. For our analysis, we used FERC’s electric quarterly reporting (EQR) data to assess the volume of bilateral trades in the SEEM footprint. Utilities file FERC EQR data to report quarterly data on their power market transactions. This includes cost-based sales, market-based rate sales, transmission service, and short and long-term power transactions.<sup>41</sup> Because SEEM executes automated bilateral trades made under each utilities’ market-based rate authority, all bilateral trades executed, both in and out of SEEM, should be reported in the EQR data, though some SEEM participants that are not FERC-jurisdictional may not be required to file.<sup>42</sup> Each quarterly report includes summary data on the counterparties of transactions, allowing us to analyze how much SEEM participants’ overall trading volumes are done specifically with other SEEM counterparties.

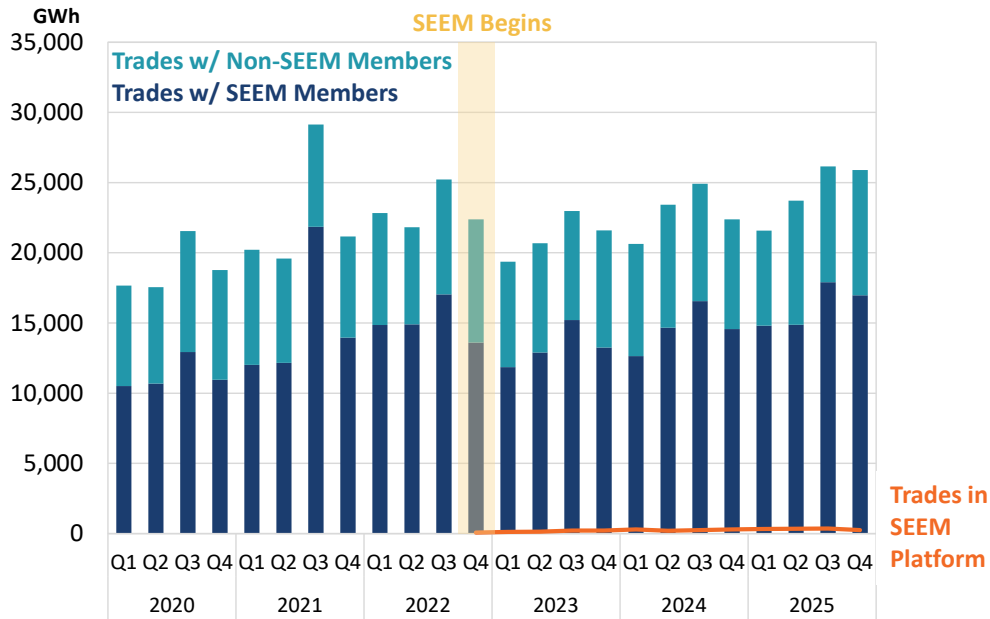
The data presented in Figure 7 shows the quantity of bilateral trading for SEEM members in the two years prior to the implementation of SEEM in the fourth quarter of 2022 and in the two plus years after SEEM implementation. The figure illustrates that the overall trend in trading has not significantly changed since the creation of SEEM. These data indicate, though, that SEEM trades are a very small portion of overall trading in the region. The EQR data suggests that SEEM members in total trade about 20,000 gigawatt hour (GWh) per quarter in recent quarters, with approximately 14,000 GWh traded directly between SEEM members. As shown in Figure 4—and confirmed by the auditor reports—the average monthly transactions in SEEM are less than 100 GWh, or about 250 GWh per quarter. This means that SEEM trading accounts for approximately 1% of overall bilateral trading in the region.

---

<sup>41</sup> [FERC Electric Quarterly Reports](#), updated March 19, 2026.

<sup>42</sup> Note that EQRs are required for FERC-jurisdictional public utilities and certain non-public utilities who make wholesale sales above a *de minimis* threshold; however, many municipal utilities and cooperatives are exempt from FERC jurisdiction and are not required to file, though they may do so voluntarily. See FERC, [Electric Quarterly Report: Filing Requirements Guide](#), November 8, 2023.

**FIGURE 7: TOTAL QUARTERLY BILATERAL TRADING BY SEEM MEMBERS, INCLUDING NON-SEEM AND SEEM TRADES**



Sources and Notes: Data on bilateral trades are sourced from FERC EQR. The BAs included in this chart for trading volumes are those that sufficient data was available for in the SEEM footprint, including Associated Electric Cooperative, Inc., Alabama Power, Dalton Utilities, Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, Georgia Power, Louisville Gas and Electric and Kentucky Utilities, MEAG Power, Mississippi Power, North Carolina Electric Membership Corporation, North Carolina Municipal Power Agency 1, Oglethorpe Power, PowerSouth Energy Cooperative, Santee Cooper (the South Carolina Public Service Authority), Seminole Electric Cooperative, Tampa Electric Company, and Tennessee Valley Authority (TVA).

It is possible that the portion of overall bilateral trades attributable to SEEM is even less than demonstrated in this analysis given the limited availability of EQR data for all SEEM members. EQR data is difficult to validate through external sources like we can for RTO or Independent System Operator (ISO) market data. There are some SEEM members for which EQR data was not found or was not entirely available. This EQR analysis is thus a best estimate of the volume of bilateral trading done in the SEEM footprint, given the limitations on publicly available data on trading volumes in the region.

Additionally, the auditor reports note that one or two utilities dominate most of the trades each month.<sup>43</sup> This suggests that trading is not broadly distributed among members, but rather concentrated between a couple of active participants, further limiting market liquidity, trading volumes, and potentially restricting the distribution of customer cost savings. If additional SEEM

<sup>43</sup> Potomac Economics, “[Monthly Audit Report on the Southeast Energy Exchange Market for November 2025](#),” December 27, 2025, p. 14. The data suggests that the top two sellers make up roughly half of the market share. Additionally, the auditor notes that the Herfindahl Hirschmann Index (HHI) is most recently above 2,000, and hovers near 1,800. For reference, US antitrust agencies consider an HHI greater than 1,800 as highly concentrated markets.

members engaged in trading as heavily as these few utilities, we would expect to see increased trading volumes and customer cost savings in the future.

## FINANCIAL BENEFIT TO THE REGION

Financially, the total savings credited to SEEM in the first year of operations was about \$3.3 million. This is less than 10% of the low estimate of savings estimated by the independent study conducted during the SEEM proposal stage.<sup>44</sup> Considering the estimated start-up and operating costs of the platform around \$4 million annually,<sup>45</sup> it is possible that the market did not provide a net benefit to the region in its first year of operations. This finding is supported by a reply brief from the Southern Renewable Energy Association in 2024 before FERC where they claimed, after reviewing invoices for services rendered to SEEM, that the total costs to operate the market in 2023 were over \$4.5 million compared to \$3.7 million in reported benefits.<sup>46</sup> While participation and benefits have increased over time, evidenced by Figure 4, the cumulative benefit of around \$22 million over three full years of operations is roughly one sixth of the expected benefits of \$120 million (\$40 million per year for the first three years of operation).

The auditor reports calculate benefits for each transaction as the bid-offer spread minus system losses. Given this approach to calculating benefits, it is possible that the actual realized benefits are different than the number reported. The reported benefits are essentially an assumed proxy for production cost savings, based on the premise that the offer price reflects the seller's production cost and the bid price reflects the cost the buyer would otherwise incur to meet load. This assumption may not always reflect reality, particularly because market participants are not required to bid or offer energy at their actual production costs. This introduces two-sided uncertainty in the benefit estimates. On the one hand, benefit estimates could be overstated if what appeared to the platform as an economic match was actually uneconomic based on unexpected or unaccounted for costs in the participant bids. On the other hand, it is possible that the benefits reported understate the savings in cases where SEEM bids include adders for desired trading margins or risk premiums, which could make the true production cost savings larger than the bid-ask spread less system losses. From our interviews with SEEM members, we understand that some utilities account for benefits beyond only production cost savings, including some avoided start-up costs of generating facilities. This data is unavailable but suggests that the benefit metric based solely on the bid-offer spread and losses is not a complete representation of SEEM benefits; however, the bid-offer spread is a reasonable measure of the market value.

---

<sup>44</sup> Guidehouse Report, p. 17. The gross benefit estimated for 2022 was \$37–\$46 million (2020\$). The \$3.3 million estimate is a nominal sum, so it would be less than that amount in 2020\$.

<sup>45</sup> This number is based on estimated costs included in the Guidehouse Report and the SEEM proposal. The Guidehouse Report estimates start-up costs of \$3.8 million, which is \$0.3 million per year levelized over 20 years, plus \$2.8 million per year of estimated operating costs, for a total of \$3.1 million per year in non-centralized costs (all values in 2020\$). The SEEM Proposal cites this number and adds to it additional start-up costs of \$1–\$5 million (\$0.05–\$0.25 million per year if levelized over 20 years) and roughly less than \$1 million of additional annual operating costs. The exact annual operating costs are not reported but based on this information it appears that approximately \$4 million per year is a reasonably conservative estimate.

<sup>46</sup> [Reply Brief of the Renewable Energy Association](#) under ER21-1111, et al., September 12, 2024, p. 3.

## D. Experience with SEEM: Interviews with Members, Participants, and Stakeholders

This section summarizes feedback on SEEM across interviews with utilities, regulators (former and current), IPPs and developers, and large power customers. The perceived value and relevance of the market vary significantly across the stakeholder groups, but there is agreement across all groups that increasing customer cost savings in the region should be maximized.

### UTILITIES SUMMARY

Utilities active in SEEM described SEEM as operating largely as designed: a voluntary, low-overhead, residual market intended to supplement—rather than replace—existing bilateral trading in the region. They have reported steadily increasing trade volumes, consistent with the market auditor reports, reliable platform performance, and the ability of SEEM to facilitate transactions that would otherwise not occur given the short duration and potentially long distances of trade. From the utilities that we interviewed, those that implemented automated systems for participating in the market saw meaningful increases in their volume of offers/bids and cleared trades. These automated systems are internal to the utilities that automatically determine available headroom and constructs bids/offers to participate in SEEM. Utilities also do not commit or dispatch generation specifically for SEEM. Instead, they only offer residual headroom. SEEM is explicitly not relied on for system balancing or reliability as the utilities in region are committed to retaining their functions as BAs.

### REGULATOR SUMMARY

State regulators interviewed expressed a mixed assessment of SEEM. Regulators characterized SEEM as an incremental extension of historical bilateral cooperation in the region, emphasizing that the states do not rely on interstate cooperation or IPPs to meet system needs. Others viewed it as minimally beneficial and operating with opaque information and governance. Transparency into customer savings varies state-to-state, with some commissions requiring timely filings and others noting that they had no information on their states' savings. Several regulators discussed difficulty in independently verifying savings or comparing SEEM's performance to alternative market structures due to limited visibility.

Importantly, regulators acknowledged political and institutional constraints on broader reform. While some expressed interest in understanding the benefits of more evolved market structures (discussed below in Section III.A), most recognized limited appetite in the region to compel structural change. It was suggested that regional coordination among regulators across states in the region could catalyze discussions on how the market could evolve to increase customer savings while also enhancing reliability and resilience.

## IPPs & LARGE POWER CUSTOMERS

IPPs were consistent in their view that SEEM is not relevant to any project development and investment decisions. Across interviews, IPPs reported that SEEM provides no meaningful contribution to originate, finance, or optimize generation projects. While IPPs can technically participate in SEEM, it was clear that an IPP would not construct a project in the region relying on revenues from SEEM. Most IPP generation in the Southeast is already contracted to a load-serving entity, leaving no uncommitted energy to sell into the market. Additionally, IPPs noted the lack of transparent data from the market that would help to influence any investment decisions. The lack of nodal or zonal pricing, day-ahead visibility, firm transmission access, and competition from non-utilities does not allow IPPs to assess curtailment risk or market value, which does not support investment decision-making or merchant participation.

Curtailed management emerged as a potential topic that developers saw as an unrealized value in the market. For renewable projects facing economic or system minimum curtailments, the platform could provide a way to send that energy to elsewhere in the region; however, interviewees reported no evidence that utilities are using SEEM to reduce curtailments. Changing contract designs between IPPs and utilities to allow the IPPs to offer their curtailed energy into the market was discussed as one way to have non-utility participation in the market. For many renewable resources—particularly qualifying facilities (QFs) operating under long-term contracts with utilities—available generation is at times curtailed due to system minimum constraints or oversupply conditions. Under existing contract structures, utilities typically retain exclusive rights to the output of these resources, and curtailed energy in many instances cannot be redirected or sold into SEEM or other markets. As a result, even when transmission is available to allow surplus generation to be economically transferred elsewhere in the region, it is not utilized. Unlocking this value would not require changes to the SEEM platform itself, but rather modifications to utility–QF contract arrangements to allow curtailed or otherwise unused energy to be offered into the market. Such changes could increase market liquidity, improve renewable utilization, and provide an additional source of income that could potentially lower the cost of QR-supplied energy.

Overall, IPPs indicated that the design of SEEM does not help increase resource development and market participation in the region, and significant changes would be required to offer meaningful opportunities for them.

We were able to interview only one large power customer in the region, but it revealed similar insights to IPPs. This large customer emphasized that they have not seen any observable impact on costs, procurement options, or clean energy growth. SEEM has not provided pricing transparency or additional contracting flexibility that would inform Requests for Proposals (RFPs) or support large-load growth beyond what is already occurring in the region. They noted that SEEM's limited scope and opaque governance are barriers to stakeholder engagement and confidence in making investment decisions.

## CROSS-CUTTING OBSERVATIONS

Across interviews, a consistent cross-cutting theme was the role of transparency and benefit attribution in shaping stakeholder perceptions of SEEM's performance. Utilities generally reported that participation produces incremental savings and operational efficiencies, and some indicated that internally calculated benefits may exceed the publicly reported bid-offer spread metric. Regulators, developers, and large customers noted that publicly available data do not allow for a detailed assessment of how benefits are distributed across participants or how they flow through to end-use customers. While SEEM publishes aggregate trading volumes and estimated benefits, participant-level and transaction-level transparency is limited relative to other organized markets. As a result, stakeholders' confidence in the magnitude and distribution of benefits varies, in part reflecting differences in access to information. Additionally, interviews highlighted differing perspectives on participation and engagement across stakeholder groups. Developers and IPPs indicated that SEEM does not currently influence project origination or financing decisions, given the predominance of long-term contracting structures and limited forward price transparency. Large customers similarly reported no observable change in procurement flexibility or pricing benchmarks attributable to SEEM. Within the utility sector, participation intensity appears to vary, with internal automation and trading capabilities affecting how actively entities engage in the platform. Taken together, these perspectives suggest that SEEM's realized benefits, which are directly tied to market utilization, could be expanded under the existing platform by increasing volumes traded among members and participants across the region.

Finally, there was broad agreement that SEEM is largely functioning as designed, but disagreement about whether that design is sufficient to deliver meaningful cost savings to customers in the region. In other words, stakeholders largely converged on the diagnosis—SEEM is working as intended—but diverged on the implication: utilities see this as an appropriate risk-managed approach, while others see it as a structural ceiling on achievable savings and system benefits. All stakeholders interviewed agreed on the desire to see more customer cost savings result from the market and its potential evolution.

## III. Benchmarking SEEM to Other Wholesale Power Markets

---

It is helpful to understand how SEEM fits within the broader spectrum of wholesale electricity market designs in the US. On one end of the spectrum are bilateral markets with minimal, if any, central coordination, and on the other end are fully centralized RTOs with day-ahead, real-time, and capacity markets (in some RTOs) in addition to centralized transmission planning and regional resource adequacy requirements. However, there are many intermediate models of wholesale market designs that exist in the US today between those two endpoints. The

introduction of SEEM represented a small move along the spectrum for the Southeast region, creating a centralized platform that allows for intra-hour bilateral trades on pooled transmission but stopping short of a regional market with centralized dispatch. This section looks at the different power market designs across the US and compares SEEM’s operations, delivered benefits, and governance to them.

## A. Market Design and Planning Elements Comparison

To provide a structured comparison, we summarize key market design and planning elements across the spectrum of US markets. Table 1 highlights the core functional distinctions among these designs (each of these market designs is detailed below). Increasing coordination meaningfully shapes the magnitude of achievable customer cost savings.

TABLE 1. SUMMARY OF MARKET DESIGN SPECTRUM AND RELEVANT FUNCTIONS

Market Design	Real-Time Regionally Optimized Dispatch	Day-Ahead Regionally Optimized Commitment & Dispatch Schedules	Transmission Access
Bilateral Trading	No	No	No pooled transmission
SEEM	No	No	Pooled for certain transactions (available non-firm capacity)
Joint Dispatch Agreement (JDA)	Yes	No	Pooled for joint dispatch (available non-firm capacity)
Energy Imbalance Market (EIM)	Yes	No	Pooled for real-time optimization (available non-firm capacity)
Day-Ahead Market (DAM) with EIM	Yes	Yes	Pooled for day-ahead optimization (typically requires firm service)
RTO/ISO	Yes	Yes	Joint transmission tariff

The spectrum of wholesale market designs operational in the US spans (in order of increasing regional coordination):

- Bilateral Trading Enabled by Transmission Open Access Policy.** In regions with only bilateral trading, utilities are typically vertically integrated utilities that are responsible for all operations and planning within their service territory. Each utility commits and dispatches its own generation to meet its own load. Trades with neighbors are arranged bilaterally, typically through long-term, day-ahead, or intra-day transactions. Negotiations for the sale of power occur manually between utilities and their counterparties. FERC policy under Order 888 requires that private entities have access to utilities’ transmission facilities under standard and publicly available rates and terms, as a means to support trade amongst bilateral

counterparties (that do not need to go through the transmission owner as an intermediary brokering each trade).

- **Bilateral Trading with Pooled Available Transmission (SEEM).** Utilities handle their own unit commitment and dispatch; they participate in a centralized trading platform with pooled transmission that eases transaction “friction” by eliminating pancaked transmission rates reducing other transaction costs. There are still no centralized commitment or dispatch procedures or transparent price signals (e.g., locational marginal prices).
- **Joint Dispatch Agreements (JDAs).** JDAs are arrangements between two or more utilities to coordinate the real-time (intra-hour timeframe) dispatch of their electricity from their generation resources across the collective service territories. The purpose is to optimize generation efficiency by optimally dispatching online generating units across the utilities’ footprints using ATC to meet load. Under a JDA, dispatch instructions for each resource are determined by an optimization algorithm and participants then settle savings among themselves. For over a decade, Duke has implemented a joint dispatch between Duke Energy Carolinas and Duke Energy Progress. Additionally, Xcel Energy’s Public Service Company of Colorado operated a JDA with other Colorado utilities (namely, Platte River Power Authority and Black Hills Colorado Energy).
- **Energy Imbalance Markets (EIMs).** An EIM is a centralized real-time market that balances supply and demand deviations across multiple BAs, typically across a broader regional footprint composed of several utilities. An EIM incorporates security-constrained economic dispatch (SCED) and transmission congestion management using an independent operator to optimize the dispatch, and some EIMs will also optimize the commitment of fast-start resources. It also produces location-specific spot prices for energy and performs financial settlement at each price location for each dispatch interval (typically five to 15 minutes). An EIM resolves any imbalance between a utility’s scheduled and actual generation and load with the most economic resources available in the entire footprint. The California Independent System Operator (CAISO) launched the Western EIM (WEIM) in 2014 and allows participants in the Western Interconnection to voluntarily join the real-time market. The Southwest Power Pool (SPP) operates the Western Energy Imbalance Service (WEIS), providing a real-time market for several utilities in the Rocky Mountain region. Similar to the WEIM, its participants retain their bilateral and day-ahead activities but turn over real-time balancing to the centralized market for efficient dispatch.
- **Day-Ahead Energy Markets (DAM).** Moving further along the spectrum but stopping short of an RTO, some regions are developing DAM designs on top of real-time imbalance markets. The idea is to capture even more regional efficiency by optimizing unit commitment and economic dispatch in the day-ahead across multiple utilities. These markets are voluntary and extend the real-time regional optimization of dispatch provided by an EIM design to the day-ahead timeframe. DAM designs are forward markets that utilize an independent market operator to co-optimize energy and transmission, which typically requires reliance on the use of firm transmission rights. There are two emerging examples of DAMs in the western US: 1) the Extended Day-Ahead Market (EDAM), administered by the CAISO, expected to launch in 2026 to expand the WEIM functionality to the day-ahead, and 2) Markets+, administered

by SPP, scheduled to go live in 2027 and will also provide day-ahead unit commitment and dispatch across participating Western utilities and real-time energy imbalance, plus potentially coordinated ancillary services. EDAM and Markets+ stop short of a full RTO as utilities retain the BA, transmission planning, transmission service provider, and generation interconnection functions. Also, EDAM and Markets+ do not include regional resource adequacy programs,<sup>47</sup> which all RTO regions include.

- Regional Transmission Organizations (RTOs).** An RTO extends beyond just an energy market, as all the RTOs in the US today take on several other functions for their regions. The RTOs act as an independent market operator to operate centralized day-ahead and real-time energy markets with SCED and commitment, typically using nodal locational pricing. They also manage regional transmission service provision and scheduling under a single regional transmission tariff and often coordinate or administer resource adequacy mechanisms (which can, but do not always, include capacity markets). They also handle regional transmission planning and generator interconnection on behalf of the region. All BA areas in the market footprint are consolidated into a single regional BA. Importantly, not every RTO is the same. There are some RTOs where utilities are vertically integrated (e.g., SPP), some with restructured utilities (e.g., CAISO; New York Independent System Operator, NYISO; Independent System Operator of New England, ISO-NE; Electric Reliability Council of Texas, ERCOT), or some with a combination of both (e.g., Midcontinent Independent System Operator, MISO, and PJM).

Table 2 displays where each US market falls within the spectrum.

TABLE 2. EXAMPLES OF US MARKETS ACROSS SPECTRUM OF MARKET DESIGN OPTIONS

Non-RTO Designs			RTO Designs				
Enhanced Bilateral Markets	JDA	EIM & DAM	Vertically Integrated Utilities		Restructured Utilities		
			Resource requirement	Spot capacity market	Resource requirement	Capacity market	Energy-only market
SEEM	Duke JDA Colorado JDA	WEIM & EDAM; WEIS & Markets+	SPP PJM (VA, WV)	MISO	CAISO	NYISO ISO-NE PJM (most states)	ERCOT

SEEM has enhanced regional collaboration in the Southeast by facilitating additional economic energy trading; however, greater customer savings and broader regional benefits may be achievable through further evolution of the market design toward deeper coordination.

<sup>47</sup> Regional resource adequacy programs are centralized mechanisms used in RTOs, and in other contexts outside of RTO markets, to ensure that enough capacity is available to meet reliability needs across the region, rather than relying on individual utilities or states to meet those requirements independently.

## B. Role of States in Market Governance

Across US jurisdictions, there is significant variation in how regional markets are governed and in the degree of transparency provided to state officials and other stakeholders. While the diverse governance structures are inherently different based on the scope of the market—RTOs have many more moving pieces than a limited market construct—it is useful to compare the institutional norms regarding the role of state regulators, the formality of stakeholder processes, and expectations around the data that is made available for stakeholders. State regulatory involvement can enhance transparency, accountability to ratepayers, and policy alignment between states in regional markets. Comparing these structures provides useful context for understanding how SEEM fits within the broader US power market landscape and how incremental changes may enhance regulatory visibility without altering the fundamental market design.

SEEM represents a relatively light-touch governance model compared to other regions in the US. Market membership and participation is voluntary, and the functioning of the market is entirely handled by its members (with the exception of the administrator and auditor, discussed previously). The Membership Board is the entity responsible for all major decisions regarding the market structure and overall operations, and the Operating Committee is responsible for day-to-day issues and operations.<sup>48</sup> Both the Membership Board and Operating Committee are comprised exclusively of representatives from the members, and there is no independent governing board or formal role for non-members (e.g., regulators, legislators, and other stakeholders) in decision-making for the market. SEEM does not include institutionalized mechanisms for state participation in governance, voting, or market rule development; therefore, oversight occurs primarily through non-coordinated, traditional state regulatory processes governing the individual utilities rather than through a regional framework embedded in the governance structure.

The extent to which state commissions receive information about SEEM and have the ability to influence market decisions varies by jurisdiction and is determined through state-specific regulatory requirements. However, it does not appear that there is a regional framework for involving commissioners in the governance of SEEM.<sup>49</sup> The market auditor, Potomac Economics, can respond to questions from regulators at any time; however, regulators have no direct oversight into SEEM operations and market results. Consequently, there is no analogous body to regional state committees in other US jurisdictions where states regularly receive briefings, coordinate on positions, and engage directly with market operators on governance and planning issues. To the extent state regulator commissions want to influence the operations of SEEM it

---

<sup>48</sup> [Operations Affidavit](#), P 22, p. 7.

<sup>49</sup> See Southeastern Association of Regulatory Utility Commissioners ([SEARUC](#)). The stated purpose of the Association is “the advancement and education of commission regulation through the study and discussions of subjects concerning the operation and supervision of public utilities to protect the interests of the people with respect to regulation of the Southeastern States.” SEARUC also includes members that are in regions not considered as part of the SEEM footprint, such as Texas and Puerto Rico.

must occur through other proceedings involving the SEEM members, such as rate cases or through the approval of resource plans.

Other non-RTO market constructs have developed more formalized interfaces with state regulators. For example, the WEIM and the emerging EDAM are governed by the Western Energy Markets Governing Body, which consists of five members that are required to be independent of market participants.<sup>50</sup> Members are selected to collectively reflect a diversity of regional expertise in the electric industry, markets, and general corporate/legal/financial experience. The members of the Governing Body are selected by a nominating committee that consists of six voting members and two non-voting members. The voting members are selected to represent the following six sectors: (1) EIM entities; (2) participating transmission owners; (3) publicly owned utilities; (4) suppliers and marketers of generation and energy service providers; (5) the Body of State Regulators (BOSR); and (6) public interest groups and consumer advocates.<sup>51</sup>

The WEIM's BOSR is made up of one representative from each of the public utility commissions of each state in which load-serving utilities participate in the WEIM and provides a forum for regulators to learn about the market, understand developments relevant to their jurisdictions, and interact with market operators and administrators directly.<sup>52</sup> The Governing Body and the CAISO regularly meet with the BOSR on market performance, proposed policy or operational changes, and market outcomes. These briefings provide a consistent opportunity for state regulators to ask questions, raise potential concerns, and influence market operations and design. The BOSR also has a memorandum of understanding with the Western Interstate Energy Board (WIEB) to enable WIEB to provide technical expertise, staff resources, and space necessary to support the BOSR's ongoing efforts.<sup>53</sup>

In terms of transparency, the WEIM provides structured reporting to participating states, including regular market performance metrics, congestion and price information, and estimates of economic benefits at both the regional and state level.<sup>54</sup> Importantly, these public benefit reports provide a clear breakdown of the benefits in each quarter (and total benefits to-date) for each of the individual WEIM participants. These materials can then easily be reviewed by state commissions, creating a shared factual record for regulatory oversight and policy discussions. This transparency framework exists despite WEIM's narrower scope relative to a full RTO,

---

<sup>50</sup> Individuals are prohibited from being a part of the Governing Body if they: (1) are employed by or provide consulting services to entities engaged in generation, transmission, marketing, trading, or distribution of electricity within the Western Electric Coordinating Council (WECC); (2) hold a prohibited financial interest; or (3) have another actual or perceived conflict of interest. See [Selection Policy for the WEM Governing Body](#), Version 1.4, July 17, 2024, pp. 7–8. Note that the governance structure is planned to transition under the new Regional Organization of Western Energy, which will oversee WEIM and EDAM. See CAISO, "[CAISO submits first Assembly Bill 825 report to Legislature and Governor](#)," News release, February 2, 2026.

<sup>51</sup> [Selection Policy for the WEM Governing Body](#), Version 1.4, July 17, 2024, p. 5.

<sup>52</sup> See Western Energy Markets (WEM), "[Body of State Regulators \(BOSR\)](#)."

<sup>53</sup> [Memorandum of Understanding \(MOU\) Between the Western Interstate Energy Board and the Western Energy Imbalance Market – Body of State Regulators](#), August 12, 2019, p. 2.

<sup>54</sup> See WEM, "[WEIM Benefits](#)."

illustrating that enhanced data sharing and regulator engagement are not exclusive to fully centralized markets. The next section compares WEIM's benefits to the realized benefits in SEEM.

In regions with RTOs or ISOs, where governance is independent from member utilities by definition, state engagement is typically more structured and institutionalized through formal regional state committees or state organizations. There is greater involvement from states and more transparent data that is made available for stakeholders to gauge the success of the markets in providing benefit to customers in the region. The role of these state committees is primarily procedural and advisory, rather than operational; however, several regions provide states with defined procedural levers that can materially affect outcomes. In fact, in some regions (e.g., ISO-NE, MISO, and SPP) the state committees retain Section 205 filing rights under the Federal Power Act related to transmission cost allocation and, in the case of SPP, resource adequacy.<sup>55</sup> State committees also interact directly with RTO boards through scheduled meetings and predictable channels to inform stakeholders of market decision-making. Table 3 summarizes the role states in governance of RTO/ISO markets around the US.

---

<sup>55</sup> Section 205 of the Federal Power Act permits utilities to propose tariff changes to FERC. In some RTO regions, state committees are granted limited authority to initiate such filings on specific issues—such as transmission cost allocation and, in SPP, resource adequacy—thereby giving states a formal mechanism to shape regional market rules, subject to FERC approval. Former FERC Commissioner Allison Clements described Section 205 filing rights as “a demonstrated means of ensuring that states’ perspectives are provided due deference in the development or regional grid operator rules and procedures.” (Allison Clements, “[Making Sense of Potential Western ISO Governance Structures: The Role of the States](#),” June 2016, Natural Resources Defense Council (NRDC) Issue Brief.)

TABLE 3. SUMMARY OF THE ROLE OF STATES IN ISO/RTO GOVERNANCE

Table ES-1. Role of States in ISO/RTO Governance and Practices						
AREA	CAISO	ISO-NE	MISO	NYISO	PJM	SPP
<i>State Commission / State Committee</i>	<ul style="list-style-type: none"> <li>▪ CPUC</li> <li>▪ CEC</li> </ul>	<ul style="list-style-type: none"> <li>▪ NESCOE</li> <li>▪ NECPUC</li> </ul>	OMS	<ul style="list-style-type: none"> <li>▪ PSC</li> <li>▪ NY DPS</li> </ul>	OPSI	RSC
<i>Sponsor Issues/Proposals in Stakeholder Process?</i>	Yes	NESCOE only	Yes	Yes	Yes	Yes
<i>Role in Stakeholder Process</i>	Non-voting	<u>Non-voting</u>	Voting	<u>Non-voting</u>	<u>Non-voting</u>	<u>Non-voting</u>
<i>Board Nomination Role</i>	<u>None</u>	NECPUC: 1 seat on Nomination Committee	State Regulatory Authorities or Public Consumer Advocates sector member <sup>(1)</sup>	<u>None</u>	<u>None</u>	<u>None</u>
<i>Board Engagement</i>	None	<ul style="list-style-type: none"> <li>▪ State official meetings (2 per year)</li> <li>▪ <u>Board liaison meeting with State Commission (1 per year)</u></li> </ul>	None	Liaison Subcommittee (~12 per year)	<ul style="list-style-type: none"> <li>▪ <u>OPSI annual meeting (1 per year)</u></li> <li>▪ General Sessions (2 per year)</li> </ul>	None
<i>Board Meeting Role</i>	Participant	None	Participant	Participant	None	Participant
<i>Form of Section 205 Filing Rights (where an entity files on their behalf)</i>	None	<u>NESCOE: Transmission Cost Allocation</u> NESCOE: Participants Committee Supported Proposal	<u>Transmission Cost Allocation</u>	None	None	<ul style="list-style-type: none"> <li>▪ <u>Transmission Planning &amp; Cost Allocation</u></li> <li>▪ <u>Resource Adequacy</u></li> </ul>

Note: Underlined items reflect differences from other participating stakeholders.

<sup>(1)</sup> Only two members of the Advisory Committee are selected, so while this could include members from these sectors, it also may not.

Source and Notes: This table is duplicated from Parent, C., K. Fisher, W. Cotton, and C. Clark, “[Governance Structure and Practices in the FERC-Jurisdictional ISOs/RTOs](#),” prepared for the New England States Committee on Electricity (NESCOE), February 2021, Table ES-1 (Role of States in ISO/RTO Governance and Practices), p. ES-2. Note that the MISO Organization of MISO States (OMS) holds seats on the MISO Advisory Committee which engages with the MISO Board of Directors. See MISO, [Advisory Committee \(AC\)](#), n.d. (Accessed on March 24, 2026).

The governance models and transparency with stakeholders across jurisdictions in the US illustrate the importance of independent governance and the role of state commissions and relevant stakeholders in advising decision-making. To effectively participate in market discussions, states and stakeholders need to be well-informed through transparent data and regular interaction with market operators. SEEM’s member-driven structure places all of the market decision-making with only the members and leaves the responsibility for oversight on individual state commissions and legislatures through traditional utility regulation, while other markets—including limited-scope markets such as WEIM—have developed more formalized mechanisms to provide states with consistent access to market information and opportunities for engagement. Differences in governance and transparency materially affect how market performance is evaluated and how benefits are communicated to regulators and stakeholders and may lead to recommended market improvements that increase customer cost savings.

### C. Delivered Benefits Comparison

Given the narrow scope of SEEM compared to market structures, as discussed in the preceding subsections, there is no directly comparable market in the US, meaning that the comparison to

benefits of other markets is not one-to-one. However, it is useful to consider the additional benefits that SEEM or other regional market structures could unlock for Southeast customers. When evaluating SEEM's early performance against other market structures across the US, it is clear that the measured benefits remain modest in comparison.

SEEM's benefits to customers are inherently constrained by its market design. The market publicly reports benefits by calculating the aggregate benefits from buyers and sellers of power using the bid and offer data. While this data may not reflect the actual total benefit if buyers and sellers have not submitted bids and offers at true production cost, benefits still accrue only to the extent of the volumes that members and participants bid into the market. This limits both the frequency and magnitude of trades and, consequently, the region-wide savings that can be realized.

On the other hand, CAISO's WEIM and SPP's WEIS provide a useful benchmark for the potential benefits that increased coordination among SEEM members could provide. As discussed previously, these two markets use non-firm ATC to enable centralized dispatch for real-time balancing of participating utilities. By providing centralized market dispatch in the real-time market, WEIM and WEIS are able to deliver significant benefits to participating utilities. For example, in its first year of operations (2021), the WEIS market delivered \$29.5 million in total benefits.<sup>56</sup> In 2022, they reported \$31.7 million in benefits compared to \$4.7 million in costs to administer the market, for a total benefit-to-cost ratio of nearly 7:1.<sup>57</sup> In its first year of operations (2023), SEEM reported total benefits of \$3.7 million compared to an estimated \$4 million in operating costs, for a total benefit-to-cost ratio of 0.93.<sup>58</sup> The WEIS footprint covers only a few BAs and around 10 utilities, all in a geographic region with limited diversity in resource mix, implying that the potential for cost savings in the WEIS is relatively small compared to the larger SEEM footprint, yet it was able to produce significantly greater benefits.

The comparison to WEIM market benefits is another useful benchmark. In its first two full years of operation (November 2014 through December 2016), the CAISO's WEIM realized \$142.6 million in benefits.<sup>59</sup> In 2016, the total market benefit was \$97 million and load within the market footprint was approximately 345 GWh, which equates to a market benefit of \$0.28/MWh. In comparison, SEEM's full second year of operations in 2024 produced market benefit of \$6.9 million with a total market load of approximately 715 GWh, which equates to a market benefit of less than \$0.01/MWh. Since its initial operating years, WEIM's geographic footprint has increased considerably and covers over 20 BAs, which is evidenced by over \$7.8 billion in

---

<sup>56</sup> SPP Markets, "[Benefit of the Market: Western Energy Imbalance Service \(WEIS\)](#)," Version 1.2, March 27, 2023, p. 1.

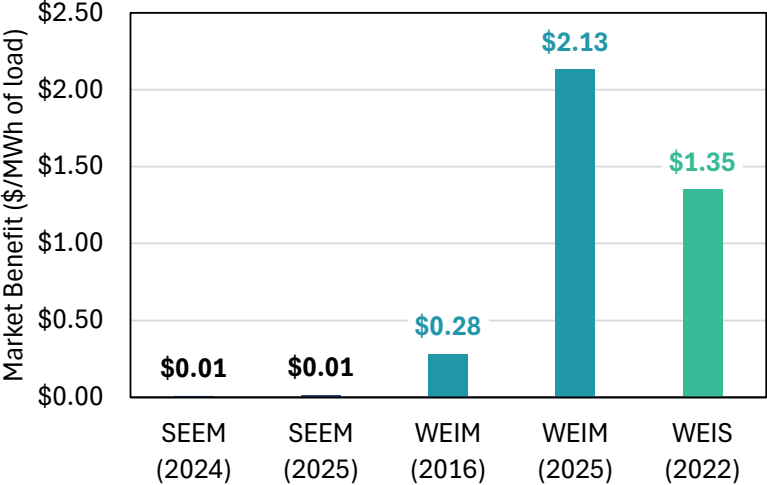
<sup>57</sup> *Id.* p. 6.

<sup>58</sup> The actual costs to administer the SEEM market are unknown. SEEM members have also indicated that actual benefits may be greater than the calculated number based on bids and offers; however, these are the best publicly available data for comparison.

<sup>59</sup> CAISO, "[Western EIM Benefits Report Fourth Quarter 2016](#)," January 20, 2017, p. 3.

cumulative market benefits since inception in November 2014.<sup>60</sup> In 2025, WEIM produced a market-wide benefit of \$2.13/MWh, which flows directly back to customers in the form of lower net power costs. Despite increasing benefits by over 50% between 2024 and 2025, SEEM still produces market benefits of less than \$0.01/MWh. Figure 8, illustrates the comparison of SEEM to WEIM at both similar nascent stages (second full year of operations) and today along with comparison to WEIS in its early stages.

**FIGURE 8. COMPARISON OF MARKET BENEFITS, NORMALIZED BY MARKET LOAD**



Sources and Notes: SEEM estimated benefits come from SEEM Public Monthly Informational Reports. WEIM benefits are from the CAISO and WEIS from SPP benefit reports, cited above.

## IV. Case Study: Factors that Catalyzed Western US Market Evolution

We believe the experience with market development in the western US provides an interesting case study for stakeholders in the southeast. The western US, outside of California, shares many similar characteristics as the southeast: the region consists entirely of vertically integrated utilities, holds a mix of investor-owned utilities, public power entities, and large cooperatives, and contains states with diverse energy policies that cannot be compromised or amended due to market participation. The process that led to the creation of regional markets in the west was very similar to the process that led to the creation of SEEM, in that it was entirely voluntary and largely utility-led, as opposed to being mandated by federal or state policy. The utilities that led the efforts to develop markets in the west created incremental changes and observed the impact of those changes on customer benefits and system operation before committing to any further

<sup>60</sup> CAISO, "[Western Energy Imbalance Market Benefits Report Third Quarter 2025](#)," prepared by Market Performance and Advanced Analytics, October 30, 2025, p. 3.

changes to the regional markets, which is consistent with the stated preference of SEEM members as they consider incremental changes to the market.

The Western Electricity Coordinating Council (WECC) has a robust and liquid bilateral trading market that is similar to the bilateral market in the southeast. Utilities and other market participants in the region trade economic energy in the day-ahead, intra-day, and in real-time timeframes and across a wide geographic footprint. A history of joint ownership of large generation resources and transmission infrastructure in the region facilitated the development of several major trading hubs, such as the Mid-Columbia (Mid-C) hub in the Pacific Northwest region and the Palo Verde (PV) hub in the southwest.<sup>61</sup> Trading hubs are physical locations where multiple utilities own generation and have long-term transmission rights connected to their loads. This structure created relatively liquid markets with many counterparties willing to buy and sell power. The standardization of contracts into peak and off-peak strips for “blocks” of power (e.g., a pre-set quantity of MWs) helped increase liquidity at the hubs, and the availability of future contracts for physical power that are publicly traded provides options for hedging price risk at the hubs and expands the trading opportunities for market participants (including financial participants) at the hubs. Outside of the hubs, utility-to-utility transactions are common in the WECC, using firm transmission service to deliver power to loads. Lastly, the existence of the CAISO market in the region allows market participants to submit intertie trades to buy or sell economic energy at the CAISO seam, similar to how utilities in the southeast make transactions at the seams with PJM or MISO.

In 2011, utilities and regulators in the western US began to formally study the possibility of creating regional markets, not to replace existing bilateral markets and trading hubs, but to layer on top of them in the hope of increasing the trading of economic energy and lowering costs for customers. A series of studies, including a 2011 study led by WECC in its role as Regional Entity for the region, and a 2012 study conducted by the National Laboratory of the Rockies (NRL) (formerly the National Renewable Energy Laboratory (NREL)), requested by regulators in the west, and a 2013 study conducted by PacifiCorp (a large utility covering six states in the west) and the CAISO, all determined that customers would experience large cost saving due to the creation of an energy imbalance market (EIM) in the WECC.<sup>62</sup> Regulators in the region formed the Public Utility Commissions Energy Imbalance Market (PUC EIM) group and asked interested parties to submit proposals on how an EIM could be implemented in the region; the CAISO submitted a proposal to create and operate an EIM in March 2012, with a draft final proposal submitted in 2013.<sup>63</sup> This ultimately led to the formation of the WEIM in 2014 with PacifiCorp and the CAISO

---

<sup>61</sup> See FERC, “[Energy Primer: A Handbook for Energy Market Basics](#),” December 2023.

<sup>62</sup> See E3, “[WECC EDT Phase 2 EIM Benefits Analysis & Results \(October 2011 Revision\)](#),” prepared for Western Electricity Coordinating Council, October 11, 2011. See also M. Milligan, et al., “[Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection](#),” Technical Report NREL/TP-5500-57115, March 2013. See also E3, “[PacifiCorp-ISO Energy Imbalance Market Benefits](#),” March 2013.

<sup>63</sup> California ISO, “[Energy Imbalance Market: Draft Final Proposal](#),” September 23, 2013.

as the first members.<sup>64</sup> The WEIM grew quickly, as several utilities in the region voluntarily joined. NV Energy announced its intention to participate in 2014 (before WEIM even went live) and Puget Sound Energy did the same in early 2015. In this manner, the creation of the EIM was largely a utility-led effort, initially by PacifiCorp and the CAISO member utilities, supported and encouraged by regulators in the region. Today the WEIM includes 22 participants and almost 80% of the load in the Western Interconnection,<sup>65</sup> as shown in Figure 9 below. In addition to the WEIM, other forms of regional markets have developed in the areas not covered by the WEIM. This includes a joint dispatch agreement between several utilities in Colorado that existed from 2016 to 2023<sup>66</sup> and a second energy imbalance market, the WEIS, established in 2021 by a group of investor-owned utilities, cooperatives, and public power entities in Colorado and Wyoming that is administered by the SPP.<sup>67</sup>

---

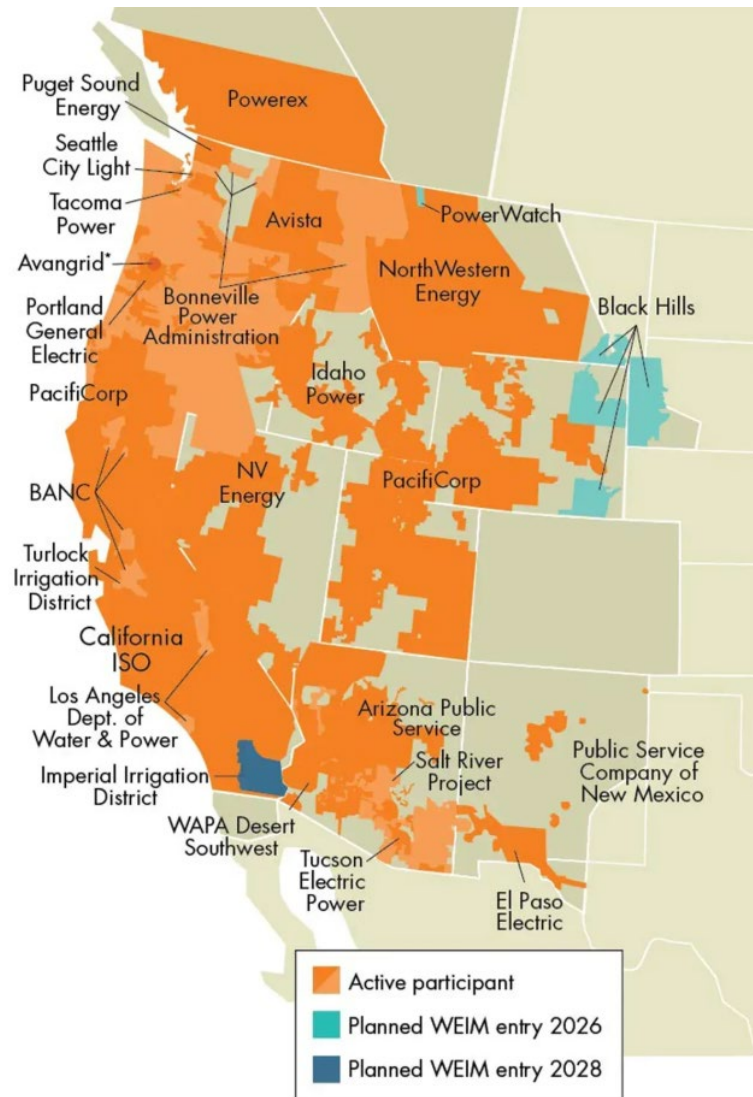
<sup>64</sup> See California ISO, "[California ISO, PacifiCorp launch first western energy market](#)," News release, November 3, 2014.

<sup>65</sup> California ISO, "[Western Energy Imbalance Market](#)," Fact Sheet, 2024.

<sup>66</sup> Xcel Energy, "[PSCo Decision to Join the EIM](#)," March 2020, slide 9.

<sup>67</sup> See SPP [Western Energy Imbalance Service Market](#).

FIGURE 9. WEIM MAP, AS OF JANUARY 2026



Source: Western Energy Markets, [WEIM Participant Map](#)

The principles that guided the development of the WEIM and other regional markets in the WECC mirror the principles that guided the development of the SEEM:

- Participation in the market is voluntary;
- Low-cost to implement and operate the market;
- Customer cost saving several times the cost of the market;
- Utilities maintain control and operation of their generation and transmission assets;
- States retain regulatory oversight of local utility planning processes; and
- Reliability and balancing function remain with the local utilities.

PacifiCorp made its motivation clear for creating the WEIM in the 2013 Memorandum of Understanding (MOU) with the CAISO. It stated that “PacifiCorp has determined there is an opportunity to secure economic benefits for PacifiCorp’s customers in the near-term through improved dispatch and operation of PacifiCorp’s generation fleet and through the efficient use and continued reliable operation of existing and future transmission facilities.”<sup>68</sup> The additional principles laid out in the MOU called for voluntary participation, for market activities to evolve based on stakeholder feedback, and that there “shall be no modification to the Parties’ respective functional responsibilities associated with reliability standards compliance.”<sup>69</sup> The benefit-cost study conducted by PacifiCorp and the CAISO found that benefits of an EIM including only PacifiCorp and CAISO would range from \$21–\$129 million/year, while the one-time cost of setting up the WEIM would be \$3 million to \$6 million and annual operating cost of WEIM would be \$2 million to \$5 million/year, implying that even the most conservative estimate of benefits would pay back the start up cost of the market in less than a year and continue providing benefits to customers in future years at four to ten times the annual cost of operation.<sup>70</sup> The founding members of WEIM pursued it because it offered a “low-cost, low-risk means of achieving operational savings”<sup>71</sup> based on the idea that “[b]etter coordination in the way we manage energy in the West is crucial to reduce costs for customers.”<sup>72</sup> In the end, this outlook proved correct as the actual benefits of WEIM to PacifiCorp and the CAISO from November 2014 to the end of Q3 2025 has averaged over \$195 million/year,<sup>73</sup> which reflects the fact the WEIM has grown to include 20 additional members beyond PacifiCorp and the CAISO.

Beyond economic benefits, WEIM has provided reliability benefits to participants in the region as well. Elliot Mainzer, president and CEO of the CAISO, has said that “the reliability value of the WEIM is potentially significantly greater than the economic value as the grid becomes more impacted by extreme weather events and an ever-changing resource mix.”<sup>74</sup> During extreme cold weather conditions in the region during the Martin Luther King, Jr. holiday weekend in January 2024, WEIM helped meet demand through energy transfers from California and the Southwest into areas experiencing shortages.<sup>75</sup> Similarly, during a September 2022 heat wave in which nearly every part of the WEIM region recorded extreme temperatures, the market demonstrated “excellent performance” and the value of wide-area coordination across the Western United States.<sup>76</sup> In addition to these event-based examples, WEIM reports show that coordinated real-time dispatch has reduced average flexible reserve requirements across the footprint by roughly

---

<sup>68</sup> [Energy Imbalance Market Memorandum of Understanding](#), Exhibit A, p. 1.

<sup>69</sup> *Id.*, Exhibit A, p. 2.

<sup>70</sup> E3, “[PacifiCorp-ISO Energy Imbalance Market Benefits](#),” March 2013, p. 4

<sup>71</sup> *Ibid.*

<sup>72</sup> California ISO, “[California ISO, PacifiCorp launch first western energy market](#),” News release, November 3, 2014.

<sup>73</sup> See Western Energy Markets [WEIM Benefits](#).

<sup>74</sup> CAISO, “[WEIM benefits report shows another historic milestone](#),” News release, January 31, 2024, p. 2.

<sup>75</sup> *Ibid.*

<sup>76</sup> Rothleder, Mark, “Featured Presentation—Reliability Through Collaboration,” CAISO, 2022.

60 percent, reflecting improved system balancing and reduced reliance on standalone backup capacity to maintain reliability.<sup>77</sup>

While the cost of implementing and operating the WEIM were very modest, the customer savings realized by participating utilities turned out to be quite large, which motivated utilities in the region to voluntarily seek to develop markets with expanded functionality and depth in the region. To date, the WEIM has produced almost \$8 billion of cumulative cost savings for customers in its footprint<sup>78</sup> and the WEIS has produced about \$30 million/year of cost savings for customers in a relatively small footprint covering Colorado and parts of Wyoming.<sup>79</sup> The realization of these benefits, the very low cost of operating the EIMs in the WECC, and the ability to participate in the EIMs without sacrificing state regulatory oversight of planning or utility operational control of resources has driven utilities in the region to push for the development of day-ahead markets (DAM) in the region.<sup>80</sup> The emerging DAMs in the region will conduct regionally optimized day-ahead unit commitment and dispatch of generation resources and schedule transmission that is made available to the market by participating utilities on a day-ahead basis. The two emerging DAMs in the WECC are the Extended Day-Ahead Market (EDAM), which will be administered by the CAISO, and Markets+, which will be administered by SPP.

A group of 14 investor-owned utilities and public power authorities signed a public letter in September of 2019 to establish the principles that should motivate and guide the development of DAMs in the WECC.<sup>81</sup> They noted that “[t]he voluntary EIM has enabled participants to reduce costs for their customers” and that the “EIM has also brought intangible benefits that have strengthened system reliability through improved operational awareness and the market’s ability to anticipate changes in loads and resources.”<sup>82</sup> The utilities go on to state that “EDAM should extend the voluntary approach that has been successful in attracting participants to the EIM” and should be developed as an “optional, incremental addition to the EIM.”<sup>83</sup> Following the principle of incremental addition to the EIM, neither of the DAMs developing in the WECC call for the markets to become the transmission service providers under a regional tariff, the consolidation of BA responsibilities under the market operator, nor for utilities to forfeit their obligations to comply with reliability standards or conduct system planning for their service territories, which would remain under the regulatory oversight of their respective states.

Following the same incremental logic, Western utilities also began exploring regional coordination beyond energy markets and into regional resource adequacy pooling and trading.

---

<sup>77</sup> CAISO, “Western Energy Imbalance Market Benefits Report: Fourth Quarter 2025,” February 13, 2026, p 3.

<sup>78</sup> *Ibid.*

<sup>79</sup> SPP Markets, “[Benefit of the Market: Western Energy Imbalance Service \(WEIS\)](#),” Version 1.2, March 27, 2023, p. 1.

<sup>80</sup> In addition to the formation of day-ahead market, several cooperatives and public power authorities in Colorado and Wyoming chose to move from the WEIS into the SPP RTO and will join in April 2026.

<sup>81</sup> [Public letter of WEIM Entities](#), September 16, 2019.

<sup>82</sup> *Id.*, p. 1

<sup>83</sup> *Id.*, pp. 1–2

The Western Resource Adequacy Program (WRAP), administered by the Western Power Pool, was initiated in 2019 as a voluntary, regional effort to establish a resource adequacy framework. WRAP creates common resource accreditation standards to manage forward-showing and operational components of the program.<sup>84</sup> Under the forward-showing component, participating utilities must demonstrate in advance that they have secured sufficient accredited capacity to meet regional planning reserve requirements, while the operational component allows participants to trade resources during hours when grid conditions are tight. In 2023, the FERC approved the WRAP tariff framework, enabling utilities to move from non-binding participation to binding compliance commitments.<sup>85</sup> By leveraging geographic diversity in load and resource profiles, WRAP is intended to improve reliability outcomes and reduce inefficient duplicative reserve procurement while preserving utility control over planning decisions and maintaining state regulatory oversight.

The evolution of regional markets and coordination in the WECC remains a voluntary and incremental process, driven by the utilities that wish to participate in the markets. Indications suggest that it will remain so for the foreseeable future. There are no plans for the emerging DAMs to evolve into anything else, particularly not an RTO. Utilities in the WECC have opted for an “a la carte” version of markets, implementing the features they think will deliver large cost savings to their customers without imposing high costs or risks or altering the reliability and planning function held by the utilities or the regulatory authority of the states.<sup>86</sup> In this sense, the principles established by utilities in the WECC to guide market development in the region reflect the same prioritizes articulated by the founding utilities in SEEM—low cost, low risk, customer benefits far in excess of costs, maintaining utility control over operations and planning, and preserving state regulatory and policy authority.

## V. Recommendations for Increasing Customer Cost Savings

---

From our interviews with stakeholders in the region, three consistent conclusions emerged:

1. SEEM is operating largely as designed; however, participation is not fully maximized, and its current structure inherently limits the scale of customer savings and provides minimal system reliability benefits.

---

<sup>84</sup> See Western Power Pool, [WRAP FAQs](#).

<sup>85</sup> See [182 FERC P 61063 \(2023\)](#). Note that summer 2025 through Winter 2027-2028 are considered transitional seasons with full binding participation beginning in summer 2028.

<sup>86</sup> Two states in the region, Colorado and Nevada, have passed laws that require utilities in their states to join organized wholesale markets (See [Colorado SB21-072](#) (2021) and [Nevada SB448](#) (2021)). The [Colorado Public Utilities Commission had adopted rules](#) related to the Colorado law on utilities’ market participation decisions in the state, which includes discussion of utility applications for waivers or delays.

2. There is broad agreement on a desire to see SEEM evolve in a way that would increase cost savings for customers and provide additional system benefits that exceed operating costs.
3. There is little appetite in the region for transitioning to an RTO.

SEEM can be evolved to provide additional customer savings by expanding participation and trading volumes in the market. The SEEM members we engaged with also stressed that changes to SEEM must be taken in a manner that reduces operational, reliability, and financial risk for customers. In this way, changes to SEEM should focus on low-cost options to implement and operate that will deliver benefits significantly in excess of costs, will preserve utility functions related to reliability and system planning, and will maintain state regulatory and policy oversight of utilities.

While there is evidence that an RTO-style market would provide cost savings for customers in the region, our conversations with stakeholders indicated that there is little appetite for this level of market reform in the region. Therefore, we do not discuss this option in detail. Multiple regions of the country have shown that RTO markets provide cost reductions to customers, and that these savings can be achieved while maintaining the vertically integrated utility model that currently exists in the SEEM footprint.<sup>87</sup> Nonetheless, stakeholders expressed concern that an RTO would imply a consolidation of BA functions across multiple utilities, moving transmission planning and interconnection functions to a regional entity, and the creation of a regional transmission tariff. Many stakeholders in the region expressed a strong desire for the utilities in the region to retain those functions.

Therefore, we have provided several recommendations and options (under two “scopes”) for evolving voluntary regional markets in the southeast that are *not* RTO markets and imply no change in the aforementioned BA functions for the local utilities and no change to state authority to determine energy policy, approve utility investments, and establish resource adequacy and reliability standards for utilities. Our recommendations include incremental enhancements to the existing platform to improve transparency and utilization (Scope 1) and low-cost options for regionally optimized markets (Scope 2) that we believe address the desire for SEEM to deliver larger cost savings to customers and provide stakeholders a diverse range of options for engagement with the market.

- **Scope 1: Incremental Enhancements to the Existing SEEM Platform.** Recommendations in this scope are changes that can be made to the existing SEEM platform without creating a new market design or structure. These recommendations may help increase cost savings for customers by addressing some of the specific issues with SEEM identified by some stakeholders, such as increased liquidity and market access, greater transparency, and an expanded role for states in governance. However, these enhancements to SEEM will not

---

<sup>87</sup> See Tsoukalis, John, et al., “[Assessment of Potential Market Reforms for South Carolina’s Electricity Sector](#),” prepared by The Brattle Group for the South Carolina General Assembly, April 2023; Southwest Power Pool, “[2024 Member Value: SPP’s Member Value Statement](#),” April 2025; [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.

deliver the same level of transparency, market liquidity, or customer cost savings as a market that conducts regionally optimized dispatch and/or commitment.

- **Scope 2: Low-Cost Options for Regionally Optimized Markets.** Recommendations in this scope are expected to greatly increase cost savings for customers in the SEEM footprint through voluntary market mechanisms without large implementation or operating costs, locking-in utilities to participate through high exit costs, or forfeiting the balancing, reliability, and planning functions.

## A. Scope 1: Incremental Enhancements to Existing SEEM Platform

Increase Transparency and Expand Reporting
Objective: Improve visibility for regulators to verify customer cost savings, IPPs to develop resources more efficiently, and large power customers to procure power at lower costs
<ul style="list-style-type: none"> <li>• <b>Publish more detailed metrics on benefits:</b> SEEM currently publishes summary statistics but could include the breakdown of benefits by utility. Some SEEM members already have a breakdown of benefits for their customers and file it with their Commissions, but this practice can be made uniform across the market for all members. Commissions can also engage with SEEM members to request information directly or from the market auditor to obtain data to review market operations.</li> <li>• <b>Provide detailed data on transactions:</b> SEEM could publish more granular data on transactions, paths, constraints, and the counterparties for each transaction and instances where the lack of available transmission or physical congestion limited the clearing of economic trades.</li> </ul>

Create a Role for State Regulators in Governance
Objective: Improve accountability and create a forum for state regulators and stakeholder engagement in market design decisions that can drive improvements to the market and further lower customer costs
<ul style="list-style-type: none"> <li>• <b>Introduce a Body of State Regulators:</b> SEEM members can consider introducing a regional body of state regulators, made up of sitting Commissioners that would oversee SEEM, provide guidance on updates or changes to the market, and create a forum for stakeholders to engage with the market. This would be the equivalent of the Organization of MISO States (OMS) in MISO, the Regional States Committee (RSC) in SPP, or the Body of State Regulators (BOSR) in the WEIM footprint.</li> <li>• <b>Increase Role of Market Auditor:</b> Revise the role of independent market auditor, which is currently focused on monitoring that SEEM performs according to its tariff, to an Independent Market Monitor that focuses on identifying efficiency opportunities in the market. This could provide a regional BOSR with an opportunity to evaluate proposed changes to the market and assess new functionality for the market.</li> </ul>

## Expand Market Trading and Liquidity

Objective: Increase market liquidity and operational efficiency to capture additional customer cost savings

### Improving Interaction with Existing SEEM Platform

- **Encourage automated utility dispatch:** Utilities that have introduced automation in determining their bids and offers into SEEM have realized increased participation in the market—if all SEEM members implemented internal automated processes for determining bids and offers into SEEM, liquidity in the market would likely increase due to a higher volume of bids and offers and a reduction in uncleared trades.
- **Opportunity to sell curtailed energy:** Allow IPP-owned renewable resources to bid economically curtailed energy into SEEM, subject to appropriate contractual modifications. This would create an opportunity to monetize surplus generation during low-load or economic curtailment periods, potentially improving renewable utilization and lowering future power purchase agreement (PPA) costs for customers. Higher revenue potential for IPP-owned resources would have the effect of lower future PPA prices, which would reduce costs for customers.

### Enhancements to SEEM Platform

- **Increase granularity of SEEM trading:** Increasing granularity to 5- or 10-minute intervals to improve operational alignment and marginal efficiency. However, we recognize that using the current e-Tag system for available transmission might make this operationally difficult and the increase in trading volume and related customer cost savings may be relatively small.
- **Expand trading products and time horizons:** Introduce additional transaction types, including hour-ahead, multi-hour, and day-ahead hourly trades. Expanding products across multiple timeframes would increase opportunities for economic trades and better utilize ATC. This aligns with the recommendations made by Potomac Economics, the SEEM independent auditor. This would require operational changes to the platform and making NFEETS service (or a similar transmission service) available across multiple timeframes including in the day-ahead. A mechanism to compensate transmission providers for capacity used by the market on a day-ahead basis can be created to incentivize providers to make transmission available to the market.
- **Explore targeted operating reserve offerings:** The SEEM may also be expanded to offer certain types of operating reserve products, backed by firm transmission, which could increase customer cost savings by allowing for reserves to be held on more cost-efficient resources.
- **Test refinements to market design to clear more transactions:** Potomac Economics has identified a large quantity of uncleared transactions within the “overlap range.”<sup>88</sup> We have not conducted an analysis of the root cause of uncleared transactions, but they may be driven by constraints in the market clearing algorithm. SEEM can test different changes to the design and evaluate benefits and cleared volumes if some constraints were altered and reformulated. If the increase in customer cost savings and cleared volumes from reformulation are significant, the market platform can be updated accordingly. We recommend testing relaxing constraints including, but not limited to, allowing individual entities to exclude select counterparties from matching. Additionally, testing running the market as a pooled matching of beneficial trades (instead of individually matching buyers and sellers) would be closer to conventional clearing optimizations and provide a uniform clearing price in each zone.

<sup>88</sup> Potomac Economics, “[Monthly Audit Report on the Southeast Energy Exchange Market for November 2025](#),” December 27, 2025, pp. 8–9.

## B. Scope 2: Low-Cost Options for Regionally Optimized Markets

All Scope 2 recommendations are voluntary, low-cost mechanisms that preserve BA autonomy, utility transmission and generation planning functions, and state regulatory authority over energy policy, investment approvals, rates, and reliability. These options would not create structural consolidation, mandatory participation, or significant exit costs or barriers for participating utilities.

Establish an Energy Imbalance Market
Objective: Enable regionally optimized real-time dispatch to deliver significantly greater production cost savings delivered to customers in the region, as evidenced by WEIM and WEIS
<ul style="list-style-type: none"> <li>• <b>Implement an EIM:</b> An EIM would unlock significantly higher customer cost savings by achieving another level of efficiency gains through regionally optimized dispatch on a 5-minute basis, regional procurement of certain operating reserves and/or ancillary services, and the sharing of unused transmission capacity in real-time (the latter feature is already a part of SEEM). The savings achieved by WEIM and WEIS in the WECC demonstrate the potential for cost reductions for customers.</li> <li>• <b>Design and operate at low cost:</b> An EIM can be implemented and operated at a relatively low cost, which would present little risk to customers in the region of not achieving cost savings above costs. For example, WEIM has saved customers almost \$8 billion in the last 11 years while only costing a few million dollars to set up and operate each year.</li> <li>• <b>Create transparent regional prices:</b> An EIM would create transparent nodal pricing signals for the region, with sub-hourly prices published shortly after market clearing for all generation and load locations in the market footprint.</li> </ul>

Develop a Regional Resource Adequacy Program
Objective: Reduce planning reserve margins and defer new capacity investments to lower overall procurement costs
<ul style="list-style-type: none"> <li>• <b>Enable regional RA trading:</b> A voluntary regional resource adequacy (RA) trading program would provide a common accreditation for generation resources, and regional planning reserve margin that leverages the diversity of peak load and variable resources in the region and provides a platform for clearing trades. This would function like a “SEEM for RA,” by enhancing the ability of utilities to trade capacity and reduce the need for new resources in the region. This could also help utilities integrate new large load customers at a lower cost, if spare capacity existed in the region and could be procured through the regional program.</li> </ul>

Implement a Day-Ahead Market
Objective: Extend regional optimization to unit commitment and day-ahead scheduling to unlock larger and more robust cost savings than real-time-only mechanisms
<ul style="list-style-type: none"> <li>• <b>Implement a DAM:</b> A regional DAM would extend the same functionality of an EIM, regionally optimized dispatch on ATC provided to the market by members, to day-ahead unit commitment and dispatch, which would unlock large customer cost savings and create transparent locational price signals for investors in the region.</li> </ul>

# List of Acronyms

---

ATC	Available Transfer Capability
BA	Balancing Authority
BAA	Balancing Authority Area
BOSR	Body of State Regulators
CAISO	California Independent System Operator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DC	District of Columbia (as in DC Circuit)
DAM	Day-Ahead Market
E3	Energy + Environmental Economics
e-Tag	Electronic Tag
EDAM	Extended Day-Ahead Market
EIM	Energy Imbalance Market
EMC	Electric Membership Corporations
EQR	Electric Quarterly Report (FERC Electric Quarterly Reporting)
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GWh	Gigawatt Hour
HHI	Herfindahl Hirschmann Index
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
JDA	Joint Dispatch Agreement
JEA	Jacksonville Electric Authority
LG&E and KU	Louisville Gas & Electric and Kentucky Utilities
MEAG	Municipal Electric Authority of Georgia
Mid-C	Mid-Columbia (trading hub)
MISO	Midcontinent Independent System Operator
MOU	Memorandum of Understanding
MW	Megawatt
MWh	Megawatt-hour
NESCOE	New England States Committee on Electricity
NECPUC	New England Conference of Public Utilities Commissioners
NEL	Net Energy for Load
NFEETS	Non-Firm Energy Exchange Transmission Service
NRDC	Natural Resources Defense Council
NRL/NREL	National Laboratory of the Rockies, formerly National Renewable Energy Laboratory

<b>NYISO</b>	<b>New York Independent System Operator</b>
<b>NY DPS</b>	<b>New York Department of Public Service</b>
<b>OMS</b>	<b>Organization of MISO States</b>
<b>OPSI</b>	<b>Organization of PJM States, Inc.</b>
<b>PUC</b>	<b>Public Utility Commission</b>
<b>PJM</b>	<b>PJM Interconnection</b>
<b>PSC</b>	<b>Public Service Commission</b>
<b>PV</b>	<b>Palo Verde (trading hub)</b>
<b>RA</b>	<b>Resource Adequacy</b>
<b>RFP</b>	<b>Request for Proposal</b>
<b>RSC</b>	<b>Regional State Committee (SPP)</b>
<b>RTO</b>	<b>Regional Transmission Organization</b>
<b>SCED</b>	<b>Security-Constrained Economic Dispatch</b>
<b>SEARUC</b>	<b>Southeastern Association of Regulatory Utility Commissioners</b>
<b>SEEM</b>	<b>Southeast Energy Exchange Market</b>
<b>SPP</b>	<b>Southwest Power Pool</b>
<b>TVA</b>	<b>Tennessee Valley Authority</b>
<b>US</b>	<b>United States</b>
<b>VA</b>	<b>Virginia</b>
<b>WECC</b>	<b>Western Electricity Coordinating Council</b>
<b>WEM</b>	<b>Western Energy Markets</b>
<b>WIEB</b>	<b>Western Interstate Energy Board</b>
<b>WEIM</b>	<b>Western Energy Imbalance Market</b>
<b>WEIS</b>	<b>Western Energy Imbalance Service</b>
<b>WRAP</b>	<b>Western Resource Adequacy Program</b>
<b>WV</b>	<b>West Virginia</b>

---

## AUTHORS



**Mr. John Tsoukalis** is a Principal at The Brattle Group with expertise in electric market modeling, analyzing regional market participation, transmission rate design, wholesale market design, utility strategic planning, and the detection of market manipulation and resulting damages analyses. Mr. Tsoukalis has modeled power systems to assess the benefits of participating in wholesale power markets, analyzed the benefits of new transmission, and valued generation assets. He has assisted clients in analyzing alternative transmission rate designs and led strategic planning initiatives to help clients plan for the ongoing transition to clean energy. Additionally, he has worked with transmission developers to analyze investment opportunities throughout the United States and Canada.

[John.Tsoukalis@brattle.com](mailto:John.Tsoukalis@brattle.com)



**Mr. Peter Heller** specializes in design and implementation strategies for policy, regulation, and market design related to the energy transition. He focuses his work on transmission and resource planning in markets across North America. Mr. Heller has experience in evaluating and designing effective transmission planning processes and economic evaluations of integrated resource plans. He also has supported expert witness testimony in a variety of electricity litigation disputes.

[Peter.Heller@brattle.com](mailto:Peter.Heller@brattle.com)



**Dr. Kathleen Spees** is a Principal at The Brattle Group with expertise in wholesale electricity and environmental policy design and analysis. Her work for market operators, regulators, regulated utilities, and market participants focuses on: energy, capacity, and ancillary service market design; the design of carbon and environmental policies; valuation of traditional and emerging technology assets; and strategic planning in the face of industry disruption. Dr. Spees has supported PJM in a number of market design efforts and modeling analyses.

[Kathleen.Spees@brattle.com](mailto:Kathleen.Spees@brattle.com)